S. HRG. 114–65

ENERGY INFRASTRUCTURE LEGISLATION

HEARING

BEFORE THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED FOURTEENTH CONGRESS

FIRST SESSION

ON

ENERGY INFRASTRUCTURE LEGISLATION

MAY 14, 2015

Printed for the use of the
Committee on Energy and Natural Resources

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ENERGY INFRASTRUCTURE LEGISLATION

THURSDAY, MAY 14, 2015

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 10:08 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. Good morning. We will call to order the meeting of the Energy Committee.

We are moving forward in the second of our series of four legislative hearings regarding the broad and hopefully, bipartisan, energy bill that our Committee is assembling.

The 22 bills included in the notice for this week's hearing address challenges related to energy infrastructure. My expectation and at the very least, my hope, is that the best ideas expressed in these bills we are considering today will ultimately become provisions of the broader bill that we intend to move later this summer.

When I think about energy infrastructure, the first thing that comes to my mind is the energy midstream which are the facilities that move energy all over the country from where it is produced to where it is used by families and businesses such as natural gas pipelines or electric transmission lines. These systems are complex yet required to work seamlessly. The expectation is that they are always going to work. Also called to mind are other softer elements of the energy infrastructure such as the quality, size and expertise of America's energy workforce. Our witnesses this morning are qualified to address each of these topics.

It is clear from reviewing the bills on our agenda this morning many Senators believe that our energy infrastructure faces challenges that require our attention. We have diverse ideas about how to strengthen the nation's energy infrastructure, and we are focused on a wide variety of topics.

Equally clear from my conversations with members on both sides of the aisle, however, is that we all recognize that the vast majority of the nation's energy infrastructure is privately owned. It is built, maintained, expanded and improved largely with private investment.

As I see it the key question presented for all of these bills and for energy infrastructure generally is what is the proper role of Federal policies in private sector investment? While many Senators

agree that energy infrastructure must be improved, there are a variety of open questions that need to be addressed. These questions include things like what qualifies as an infrastructure improvement? Are legal and regulatory barriers standing in the way of technological improvements and advancements? How do we ensure that Federal permitting is more timely, consistent and certain while continuing to meet all the requirements of the law?

Finally, it is obvious Senators are prepared to give significant attention to Federal law governing electricity and the uniquely critical grid infrastructure.

Our hearing in March on the state of technological innovation related to the electric grid established that a cumulative investment of between $300 and $500 billion over the next 20 years will be required. How will Federal law and policy influence that investment, and how can we ensure that Federal policies lead to positive change? Further how can we avoid the unintended consequences of reliability losses, unwarranted or undisclosed price increases inhibiting technological innovation or stifling customer preferences?

Those are the questions that we are seeking answers to, and I hope that today's hearing will prove useful in this regard.

We have already learned that today's developments in electricity have tremendous potential but also present a number of challenges such as smoothing out the intermittency of variable weather dependent generation. With the rise of distributed generation and smart grid technologies, Americans are gaining more control over how they use and consume electricity but the grid must be even more closely integrated as a result.

As eager as we all are to contribute to the arrival of a smarter, more futuristic energy infrastructure, I think we policy makers must first do no harm. This maxim holds true for our efforts regarding the construction, security and regulation of pipelines, transportation, information technology and other infrastructure as well. I hope this Committee can continue with the deliberative approach that we have employed in all of the hearings leading up to today. I thank our witnesses in advance for their contribution to that end.

With that, I will turn to our Ranking Member, Senator Cantwell, for her comments, and then we will move to the panel of witnesses assembled this morning.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Thank you, Chairman Murkowski, and I so appreciate that we are having a hearing today on energy infrastructure. It is probably one of the most important and also complicated areas that we are going to try to deal with in energy legislation.

The vast majority of our energy infrastructure in the U.S. is owned by private industry. And it is governed by a patchwork of Federal, state and local laws, which collectively determine the level of investment this infrastructure attracts and the competitive conditions by which it is operated.

When Secretary Moniz was here last month to talk about the Quadrennial Energy Review, he made a very compelling case that

we are at an energy crossroad. The dynamic and changing nature of our domestic resource mix—and not just expanded supplies of natural gas, but also the growth of distributed generation—is creating both new challenges and great opportunities.

When you add extreme weather events and the changing climate as variables, we need to consider resilience in our infrastructure investment, making sure that we also are making it part of a key energy security equation.

In reviewing the status of our energy infrastructure, I believe the Quadrennial Energy Review did us a service in mapping out some of the most pressing challenges and opportunities. Specifically it recommended five major priorities.

One, taking steps to bolster the resilience, reliability, safety, and security of our infrastructure. Second, modernizing our electric grid. Third, modernizing our energy security infrastructure, like the Strategic Petroleum Reserve, to keep pace with the changes in the energy picture. In addition, improving our shared transportation infrastructure for energy commodities like rail and barge, and, lastly, better integrating North American energy markets.

While looking at our agenda today, it is clear that Senators across the board recognize that upgrading our grid infrastructure will enable the integration of new technologies that benefit our competitiveness and benefit consumers. We have numerous bills dealing with grid modernization. This is because smart, targeted Federal investments that cultivate public-private partnerships for research, development, and demonstration will pave the way toward new solutions.

This is something, I think, that is unique to the U.S. economy and a huge economic opportunity.

That is what is required to generate the kind of trillion-dollar private-sector investment needed to retrofit our energy infrastructure and to keep pace with the needs of a 21st-century economy and security.

As such, I look forward to the testimony of all our witnesses on this subject.

In particular, I am pleased to welcome Ms. Ericson, our witness from Alstom. The Alstom Grid Center of Excellence is located in Redmond, Washington. They have a great story, and I look forward to hearing more about them today.

There are many opportunities associated with the grid, as a platform for both security and innovation. And I know we are going to have a hearing later on workforce issues, but I hope to touch a little bit on that today. It has definitely gotten my attention that the energy industry is expected to add 1.5 million workers in the next 15 years, and about 200,000 more workers with computer science and math skills are projected to be needed.

I want to ensure we have that energy workforce for tomorrow, so we can take advantage of that huge investment opportunity. And I want to make sure we are delivering the right workers with the right skills. I think that we have a lot of opportunity with the Department of Energy on that.

The grid is obviously a topic of interest to members on both sides of the aisle. But, judging by the wide range of proposals before us—especially with respect to amending PURPA, the Public Utility

Regulatory Policy Act of 1978—the Committee also has a significant amount of work to do, to figure out the right approach to creating conditions for innovation in the electric distribution system.

Obviously the topic goes hand-in-hand with what we want to do on the grid in cybersecurity. And Senators Risch and Heinrich have a proposal, which mirrors legislation this Committee has reported on a few prior occasions. I have also introduced the Enhanced Grid Security Act to tackle this important subject. Getting this right and getting cybersecurity right will be important to everyone.

Finally, we have on the agenda today a number of siting and permitting proposals. There is undoubtedly room for improvement in our process, especially with respect to integrating coordination and how we can move these processes along. We have a number of very significant policy suggestions before us, like: creating additional Federal authority for oil pipelines at FERC, making it easier to site pipelines in National Parks, rewriting an executive order on cross-border infrastructure projects—obviously none of which I support.

We also have two diametrically opposed approaches to electric transmission siting. I think you will remember the markup we had when we had a siting discussion before, in 2009. There were approximately a dozen amendments and it took two days. I am sure when we get to those issues again, there will be similar discussions with a wide range of approaches of what to do.

But clearly we are here because we want to move our infrastructure investments forward. We want the U.S. to continue to grow a strong and resilient infrastructure for our energy needs and to seize the economic opportunities available to the United States, as we look at smart grid leadership around the globe.

So, thank you, Madam Chair for holding this hearing, and I look forward to the testimony of our witnesses.

The CHAIRMAN. Thank you, Senator Cantwell.

This morning we have a diverse group of panelists that have come before the Committee.

We will begin with Ms. Erica Bowman. Ms. Bowman is the Vice President of Research and Policy Analysis and Chief Economist at America's Natural Gas Alliance. She is going to start us off with a discussion of everything from LNG export facilities to new and expanded pipelines.

She will be followed by Mr. Jonathan Weisgall, who is the Vice President of Legislative and Regulatory Affairs at Berkshire Hathaway Energy, to provide a view from a company that owns significant critical infrastructure and also faces challenges because of an outmoded Federal purchase obligation.

Ms. Amy Ericson will be next in the lineup. She is Alstom's Country President for the United States and she is here to offer the views of one, as her company has put it, who is engaged with U.S. policy stakeholders while directly supporting pursuit of new business opportunities in the areas of thermal and renewable power generation and electricity transmission and distribution.

We also have with us this morning Mr. Greg Dotson. Mr. Dotson is the Vice President for Energy Policy at the Center for American Progress. He is here to share the perspective of one of the many good think tanks based here in Washington, DC. We appreciate you being with us.

Mr. Jim Hunter is the Utility Department Director at the International Brotherhood of Electrical Workers which represents more than 220,000 union members who are part of our nation's electric industry workforce. He will ensure that we keep the perspective of the workforce firmly in mind as we debate the changes to electricity laws which we greatly appreciate.

Finally, we have the Honorable Brian Kalk, who is a Commissioner on the North Dakota Public Service Commission. Dr. Kalk will present a state perspective this morning which is invaluable because state retail regulation is central to the health of the electric sector and because so many of the bills that are up for discussion today instruct states to examine or reexamine their own policy. So we will look forward to that state's perspective as well.

Again, thank you each for joining us here this morning. Let us begin with Ms. Bowman.

Each of you will be afforded five minutes. Your full testimony will be included as part of the record, and then we will have an opportunity for questions to each of you.

Ms. Bowman, welcome.

STATEMENT OF ERICA BOWMAN, VICE PRESIDENT, RESEARCH AND POLICY ANALYSIS, AMERICA'S NATURAL GAS ALLIANCE

Ms. BOWMAN. Chairman Murkowski, Ranking Member Cantwell and members of the Committee, thank you for the opportunity to testify this morning.

We are at a pivotal moment in determining our nation's energy future. The topic of today's legislative hearing is an important and timely one strengthening our nation's energy infrastructure.

Over the past decade we've experienced a paradigm shift in our energy landscape. As a result of the technological innovations and the ingenuity of the men and women of the oil and natural gas industry, our nation has moved from a posture of scarcity to one of abundance. The U.S. is now the world's leading producer of natural gas. This shale revolution has helped—driven economic growth, fostered environmental stewardship and strengthened America's energy security.

So the question before this Committee is how do we ensure that America takes full advantage of the opportunity presented by the abundance of this clean, affordable, reliable and domestic resource?

ANGA has a few ideas about this that I'd like to share with the Committee, but first I think it is important to set the stage and put into perspective exactly what I'm describing when I talk about the shale revolution and the benefits that flow from it.

U.S. natural gas consumption in 2014 totaled 27 trillion cubic feet. The total volume of natural gas reserves recoverable using existing technology is more than 100 times greater, over two thousand eight hundred trillion cubic feet. And the Energy Information Administration recently projected that domestic natural gas production and stable prices will remain for decades to come even with increasing natural gas consumption for power generation, manufacturing, heating and export.

The greater use of natural gas in America will continue to spur economic growth, create good paying American jobs, help our clean—help clean our environment and strengthen our energy secu-

rity. These new infrastructure projects will create employment and economic benefits, but the economic benefit from infrastructure development itself is only one small part of a much larger equation.

It is widely recognized that the oil and natural gas sector provided the primary source of economic growth during the great recession, and this significant contribution is expected to continue.

In 2012 the sector contributed $238 billion to gross domestic product. This is projected to grow to $475 billion by 2025.

That economic activity fueled additional growth in the NG sectors as well such as the petrochemical manufacturing which contributed $7 billion in 2012 and is expected to grow seven fold to $51 billion in 2025.

In fact just this week Energy Secretary Ernie Moniz credited low cost natural gas with contributing to the revitalization of our nation's manufacturing sector.

Pipelines also link our natural gas supplies to electric generators. Natural gas use in power generation has been credited with reducing both criteria pollutants and greenhouse gas emissions. Researchers at the National Oceanic and Atmospheric Administration found that the increased use of natural gas in power generation has led to 40 percent less nitrogen oxide emissions and 44 percent less sulfur dioxide emissions since 1997.

Additionally EIA found that increased use of natural gas has reduced overall greenhouse gas emissions by 212 million metric tons in 2013 when compared to 2005 levels.

In addition to these increased domestic uses our abundant supplies enable our nation to export to our allies abroad. Exporting U.S. natural gas is a win/win proposition that will strengthen the economy, improve our trade balance and allow us to be a global energy leader.

The Council of Economic Advisors 2015 Annual Report found that LNG exports will increase domestic production and create more jobs. Further, the report found that exporting U.S. natural gas will lower the prices around the world which will have a positive geopolitical impact on the United States.

U.S. LNG export capacity will enable bidirectional capability in the global marketplace and support the buildout of domestic energy infrastructure which strengthens our nation's energy resiliency.

A world class pipeline infrastructure system is the link enabling the U.S. economy and environment to realize the benefits of the shale energy revolution. In order to achieve the necessary expansion and improvement in our pipeline infrastructure system we need to reform the process for getting pipelines sited and built. This requires improvements in the permitting process at the Federal level as well as political will and action at the state and local levels.

I look forward to answering questions about the benefits natural gas can provide and the changes we believe will benefit infrastructure development.

Thank you.

[The prepared statement of Ms. Bowman follows:]

TESTIMONY OF ERICA BOWMAN,
VICE PRESIDENT, RESEARCH AND POLICY ANALYSIS
AMERICA'S NATURAL GAS ALLIANCE

SENATE ENERGY & NATURAL RESOURCES COMMITTEE

MAY 14, 2015

Introduction

Good morning, Chairman Murkowski, Ranking Member Cantwell and Members of the Committee. Thank you for the opportunity to testify today. My name is Erica Bowman. I am Vice President for Research and Policy Analysis and Chief Economist at America's Natural Gas Alliance (ANGA).[1]

We appreciate the opportunity to testify in support of legislative efforts to strengthen our nation's energy infrastructure. I will limit my remarks today to specific legislation, addressing energy infrastructure and LNG exports, in the series of bills on the agenda for this legislative hearing.

ANGA supports S. 1210 introduced by Senator Capito and co-sponsored by Senator Heitkamp. This legislation will help improve coordination between FERC and other permitting agencies involved in federal authorizations for siting interstate natural gas pipelines and we believe this bill is a step in the right direction toward streamlining permitting while protecting reasonable and sufficient public input in the process.

ANGA supports S. 1196, introduced by Senator Cassidy and co-sponsored by Senators Inhofe and Capito. This legislation would amend the Mineral Leasing Act to clarify the authority of the Secretary of the Interior in siting natural gas pipeline rights-of-way across federal lands. As pipeline developers continue to experience project delays and added costs as a result of permitting challenges, we support legislative efforts to provide greater certainty to the siting and permitting of energy infrastructure projects in a timely and cost-effective manner while maintaining appropriate public input.

ANGA opposes legislation that seeks to limit liquefied natural gas (LNG) exports by prohibiting the Department of Energy (DOE) from approving applications that will result in

[1] ANGA represents North America's leading independent natural gas exploration and production companies. We work with industry, government and customer stakeholders to increase demand for, and ensure availability of, our nation's natural gas resources for a cleaner and more secure energy future. The collective natural gas production of ANGA member companies is approximately eight trillion cubic feet annually, which represents one third of total U.S. production.

surpassing arbitrary export thresholds. Concerns that LNG exports will harm domestic consumers of natural gas are unfounded. In their 2015 Report to the President, the White House Council of Economic Advisors found that LNG exports would result in economic and national security benefits for the United States.[2] A cap on LNG exports volume is unnecessary and will have negative effects on the ability of U.S. natural gas to compete in the global marketplace staunching our opportunity to capture value from the international LNG market and forsaking the domestic and foreign policy benefits associated with LNG exports.

ANGA opposes legislation requiring the Federal Energy Regulatory Commission (FERC) to consider regional constraints in the natural gas supply and to consider whether a proposed LNG terminal would benefit regional consumers of natural gas before approving or disapproving an application for the LNG terminal. Natural gas supply, demand and the connections that link them evolve over time. Such a policy does not take into account the movement of natural gas throughout the country or the past actions of states or localities that may constrain their own supplies of natural gas. Further, an economic analysis is already considered by the FERC during the application review process.[3]

The broader subject of today's legislative hearing - strengthening our nation's energy infrastructure - is an important one for our nation's future. As a result of the shale energy revolution, America has moved from a posture of energy scarcity to one of energy abundance. This paradigm shift is helping to drive economic growth, environmental stewardship and energy security. However, to fully realize the enormous potential presented by our natural gas abundance, it is imperative that we support the acceleration of natural gas infrastructure development in all regions of the United States. A modernized infrastructure system alongside a rational and predictable regulatory regime will lead to a more secure connection between rising natural gas production and growing regional natural gas demand. Achieving this balance will help us take full advantage of our vast domestic energy resource and strengthen our energy security.

Substantial reserves of natural gas in the United States have led to significant, positive change in our domestic energy outlook. The Potential Gas Committee's (PGC)[4] recently issued biennial report found a record natural gas resource assessment for the sixth consecutive report. U.S. natural gas consumption in 2014 totaled 27 trillion cubic feet (Tcf), while the total volume of U.S. natural gas recoverable *with existing technology* is more

[2] White House Council of Economic Advisors, "Economic Report of the President", February 2015, 261 accessed May 11, 2015, http://www.whitehouse.gov/sites/default/files/docs/cea_2015_erp.pdf.
[3] FERC, "Pre-Filing Environmental Review Process," accessed May 12, 2015, https://www.ferc.gov/help/processes/flow/lng-1-text.asp.
[4] A group of highly knowledgeable and experienced geologists, engineers and others who, since 1964, have assessed the technically recoverable natural gas resource base in the United States on a biennial basis. The Colorado School of Mines leads the work with the PGC.

than 100 times greater - over 2,850 Tcf. In addition, the U.S. Energy Information Administration's (EIA) 2015 Annual Energy Outlook (AEO) projects increased domestic natural gas production and stable prices for decades to come—even with rising natural gas consumption across power generation, industrial usage, space heating and exports.

Not only have reserves, production and consumption grown, but so too has the number of regions in the United States that produce natural gas. This geographic diversity has led to increased regional opportunities to use this domestic resource to meet rising demand for affordable, clean power generation, manufacturing fuel and feedstock as well as exports.

These conclusions have been confirmed by the DOE's newly released *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure*. The DOE notes that:

- Without shale gas, U.S. natural gas prices would be 70 percent higher than projected prices by 2040.
- The availability of lower-cost natural gas and natural gas liquids provides an advantage to U.S. manufacturers.
- Natural gas has enabled an economic option to reduce emissions in power generation and that the U.S. has enormous capacity and reserves and will likely become a major natural gas exporter.[5,6]

For the regional opportunities presented by our natural gas abundance to fully materialize, the new facilities currently under construction, from power plants to manufacturing facilities to LNG export terminals, will need additional infrastructure to connect them to their respective natural gas supply basins.

The DOE found that most infrastructure siting and permitting decisions are made at state and local levels and that close stakeholder interaction and knowledge of local resources and sensitivities is required. However, the DOE also found that state agencies lack the incentives to act on multi-state projects when the projects' perceived "beneficiaries" are located in other states.[7] ANGA recognizes the complexities associated with pipeline projects and encourages a robust stakeholder process to address these potential issues. ANGA urges all stakeholders with proposed natural gas infrastructure projects in their regions to fully recognize and evaluate the energy security and economic opportunities these projects present and to effectively educate the broader public about the benefits of these important infrastructure initiatives.

The following testimony details the regional benefits that natural gas infrastructure projects provide. In addition, the testimony highlights the unique circumstances

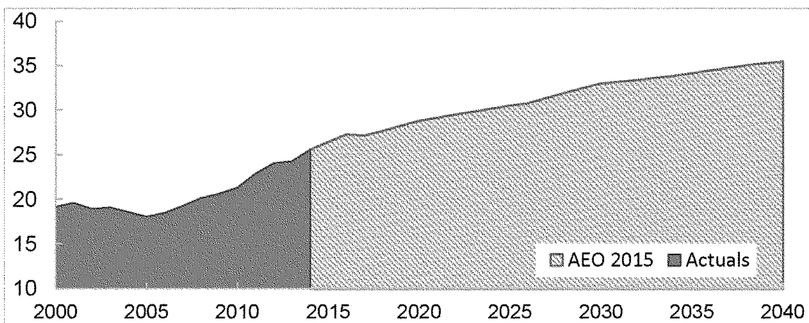
[5] DOE, "Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure," April 2015, 1-6 – 1-7.
[6] Ibid, 4-2.
[7] Ibid, 9-7.

surrounding the infrastructure-constrained Northeast and ways for additional U.S. regions to avoid this fate.

Supply, Demand and the Importance of Infrastructure

America's abundant natural gas supplies will be consistently available to power our nation's economy for generations to come. The United States is the world's leading producer of natural gas—ahead of Russia and Iran. Future projections show this trend continuing. Since 2005, U.S. natural gas production has increased 41 percent. EIA's 2015 Annual Energy Outlook (AEO) projects a further 34 percent increase in production from 2015 to 2040.[8]

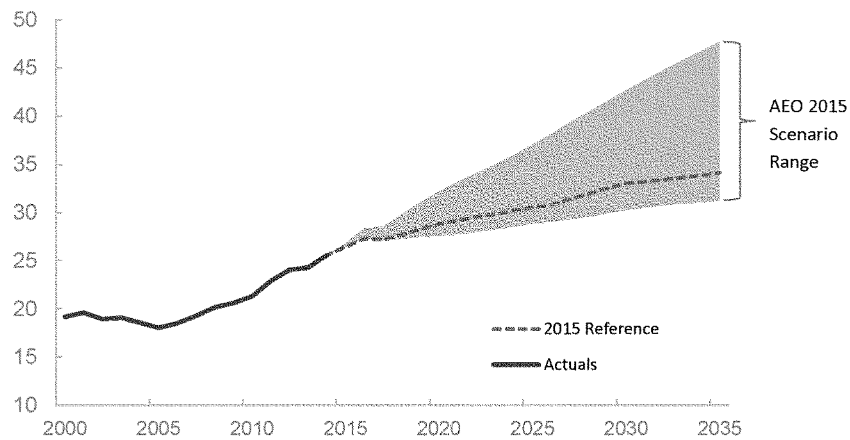
Figure 1: U.S. Natural Gas Production (TCF): Actuals and Reference Case



Additionally, natural gas demand has increased 23 percent since 2005 and the EIA 2015 AEO projects a further 29 percent increase in demand from 2015 to 2040 in the reference case (this demand growth includes exports).[9]

[8] EIA, "Annual Energy Outlook: Total Energy Supply, Disposition, and Price Summary, Reference Case Table," April 2015, accessed May 5, 2015. Reference case.
[9] Ibid.

Figure 2: U.S. Natural Gas Demand (TCF): Domestic Consumption and Exports



Demand for U.S. natural gas is expected to grow across all scenarios evaluated in the EIA 2015 AEO with the potential upside in demand growth significantly higher than the reference case.[10] These projections of increased production and consumption for natural gas are further evidence of the urgency to modernize our energy infrastructure system in order to keep pace.

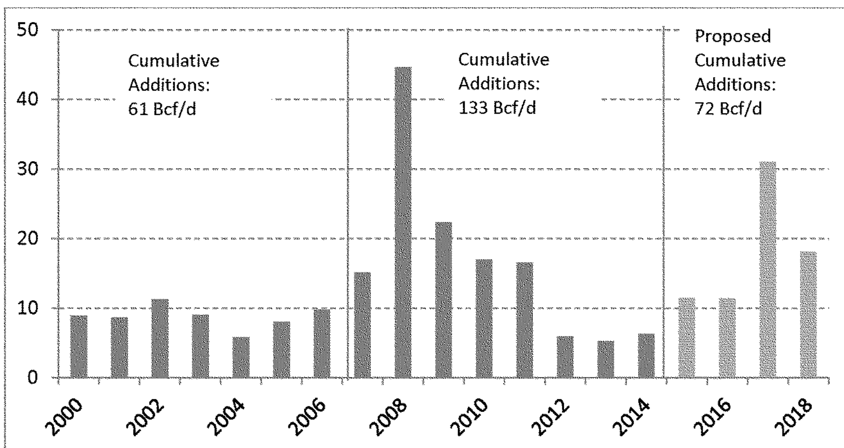
The U.S. has the most extensive natural gas pipeline system in the world – more than 300,000 miles of major intra- and interstate gas pipelines.[11] It is essential that our nation's natural gas infrastructure be optimized to connect natural gas supplies to demand centers. This infrastructure is the system through which our entire country can benefit from our prolific and affordable natural gas resources. Without such infrastructure, U.S. regions lacking indigenous supplies of natural gas will need to use more expensive, alternative fuels for power generation, space heating and industrial processes or could see growth constrained.

[10] EIA, "Annual Energy Outlook: Total Energy Supply, Disposition, and Price Summary Tables: Reference Case, Low Oil Price Case, High Oil Price Case, Low Economic Growth Case, High Economic Growth Case, High Oil and Gas Resource Case," April 2015, accessed May 5, 2015.

[11] Pipeline and Hazardous Materials Safety Administration, "2014 Gas Transmission & Gathering Annual Data", accessed May 5, 2015, http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

Since 2007, the beginning of the shale gas revolution, more than 130 Bcf/d of pipeline capacity has been added to the natural gas interstate and intrastate pipeline systems. This is more than double what was added between 2000 and 2006, and an additional 72 Bcf/d of pipeline capacity has been proposed through 2018. To put this in perspective, one billion cubic feet of natural gas is able to meet the total natural gas needs (including power generation) of the state of Arizona for one day. We need to continue this progress through the support of proposed pipeline projects at the federal, state and local level to ensure our nation's abundant natural gas supplies are able to connect to the growing demand of U.S. consumers and businesses.

Figure 3: U.S. Pipeline Capacity Additions[12]



The pipeline additions provide significant and broad economic benefits. Among these are well-paying jobs, which Sean McGarvey, President of North America's Building Trades Unions, remarked on in late 2014, "Simply put, the development of our nation's domestic energy resources is the single biggest contributing factor for job growth in the U.S. construction industry today, as well as other sectors of our economy." For every incremental billion cubic feet per day of natural gas produced in the United States, approximately 15,000 to 21,000 direct and indirect jobs are created, which include equipment manufacturers, oil and gas service jobs, material suppliers and others.[13] In 2012, unconventional oil and gas activity contributed approximately $63 billion in federal,

[12] EIA, "U.S. Natural Gas Pipeline Projects," April 2015, accessed May 5, 2015.
[13] ICF, "Tech Effect: How Innovation in Oil and Gas Exploration Is Spurring the U.S. Economy," October 2012, 4.

state and local tax receipts. By 2020, this revenue is expected to grow to more than $110 billion.[14] Achieving the full potential of this employment and revenue growth depends on robust, reliable infrastructure that can move natural gas from areas of development to regions eager to put it to use.

Infrastructure Challenges: Lessons from New England

The energy infrastructure challenges in New England are well documented, as are the resulting strains placed on consumers. DOE has found that despite large volumes of new unconventional gas resources available from the Marcellus Shale in nearby Pennsylvania, pipeline constraints have not allowed sufficient supplies of natural gas to reach New England, resulting in upward pressure on prices during peak demand times. The New York City area, by contrast, has alleviated winter congestion by adding new pipeline capacity.[15]

New England has several unique characteristics that differentiate it from other regions of the country. While choices over the past decade have contributed to the problem, there is emerging consensus among the region's current political leaders that the time has come to address these shortcomings so New England can reap the same benefits from natural gas that the rest of the country enjoys.

New England's geology is not conducive to the production or underground storage of natural gas. This forces the region to rely solely on pipeline capacity and more expensive LNG storage to meet peak natural gas demand days. This typically occurs only in the coldest parts of winter when existing pipelines strain to meet peaks in natural gas demand for both heating and electricity. In non-winter months, without the winter residential and commercial heating demand, there is ample pipeline capacity to serve the region's natural gas needs.[16]

To achieve environmental goals, two trends have occurred concurrently in New England. Residential and commercial natural gas demand has grown over time along with natural gas demand in the electric generation sector.

The Natural Gas Act requires an interstate natural gas pipeline to seek a "certificate of public convenience and necessity" from FERC.[17] Any new or expanded pipeline capacity

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[14] IHS, "America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy – Volume 2: State Economic Contributions," December 2012, 14.
[15] DOE, "Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure," April 2015, 2-27.
[16] EIA, "Northeast natural gas spot prices particularly sensitive to temperature swings," August 2014, accessed May 5, 2015, http://www.eia.gov/todayinenergy/detail.cfm?id=17491#tabs_SpotPriceSlider-3.
[17] 15 USC Section 717f.

must be subscribed – while no set subscription percentage is required, often 80 percent is used as a guiding threshold as to whether or not a project moves forward.

Local distribution companies are required to purchase natural gas via firm contracts that ensure sufficient pipeline capacity and storage to meet customer demand on peak demand days. They also are allowed to sell off excess, unused capacity on the spot market. Merchant electric generators typically purchase this surplus, which comes at a lower cost but without any guarantee of delivery on peak days when demand exceeds deliverable supply.

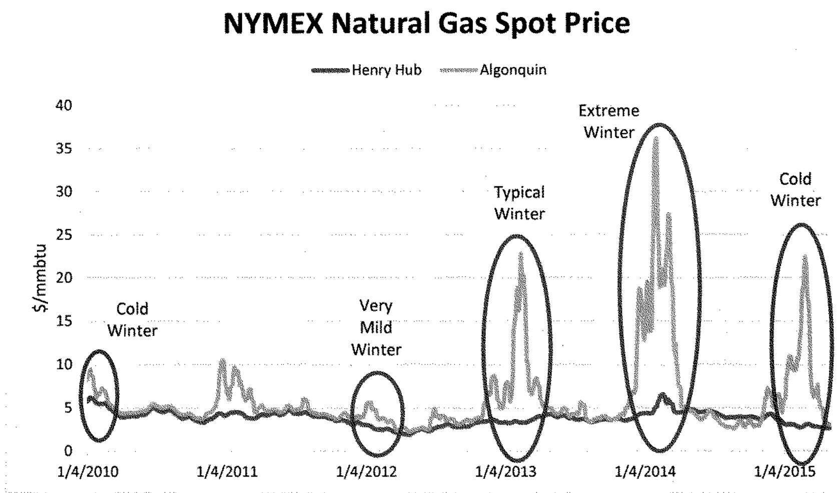
Unlike regions where cost-recovery for new power generation capacity and associated fuel supply is recovered through state public utility commission action, New England relies on New England's independent system operator (ISO-NE) - the regional market operator - to appropriately procure resources to meet future load.

While ISO-NE market rules have changed to improve resource adequacy and resource performance for incoming capacity post June-2018, the region has had limited options for merchant electric generators to recover cost for firm natural gas pipeline capacity.[18] Given this, natural gas generators have not entered into firm contracts with pipeline companies; hence, natural gas electric generators depend on LDC pipeline capacity release for their fuel supply leading to electric generator capacity uncertainty during high residential and commercial heating demand days. Even with ISO-NE market changes, ISO-NE expects additional infrastructure will be needed to meet growing demand for natural gas.[19]

In addition to the electric market structure, from a political perspective over the past decade, it has been difficult to develop any energy infrastructure to serve New England including electric transmission lines delivering hydropower from Canada, offshore wind in Nantucket Sound and natural gas pipelines into the region due to a host of issues, including local concerns over property values, environmental issues and quality of life. These decisions have occurred simultaneously with increased reliance on natural-gas fired electric generation due to generation retirements in the region and increased use of natural gas in the residential and commercial sector.

[18] ISO-NE, "Challenges Facing the New England Power System," March 2015, 13.
[19] Ibid.

Figure 4: New England Prices vs. Henry Hub ($/MMBtu)[20]



The above graph depicts the difference adequate infrastructure makes. The blue line reflects low, stable natural gas prices at the Henry Hub, which is considered a proxy for increasingly homogenous U.S. natural gas prices on the spot market. As natural gas production and overall supply estimates have grown, the majority of regions across the United States have benefited from affordable natural gas prices.

By contrast, the green line represents prices at the Algonquin Citygate, which reflects the New England market. Due to the region's seasonal infrastructure constraints, prices in the Northeast spike even during "typical" winters, as experienced in 2013. The record cold of the polar vortex of 2013-2014 put additional strain on Northeast pipelines, which further exacerbated spot prices there. Once demand exceeded deliverable supply, prices spiked and remained high for most of that winter. This past winter, prices remained high. While not as high as the winter of 2013-2014, the price differentials continued to signal a strong need for additional natural gas pipeline capacity into the region. The New England region needs not only the changes made by NE-ISO, but also political will and efficient permitting processes to usher additional pipeline capacity into the region.

[20] NYMEX Spot Prices, 14-day moving average.

The bottom line: Natural gas price spikes are increasingly an anomaly in the new era of shale abundance. They exist in New England due to a disconnect between supply and demand—namely inadequate pipeline infrastructure. Sufficient pipeline capacity mitigates regional price spikes. Regions should support additional pipeline capacity, including permitting timetables that provide for appropriate public input without unreasonable delay, to enable deliverability capability and flexibility.

Infrastructure Opportunity: Marcellus and Utica

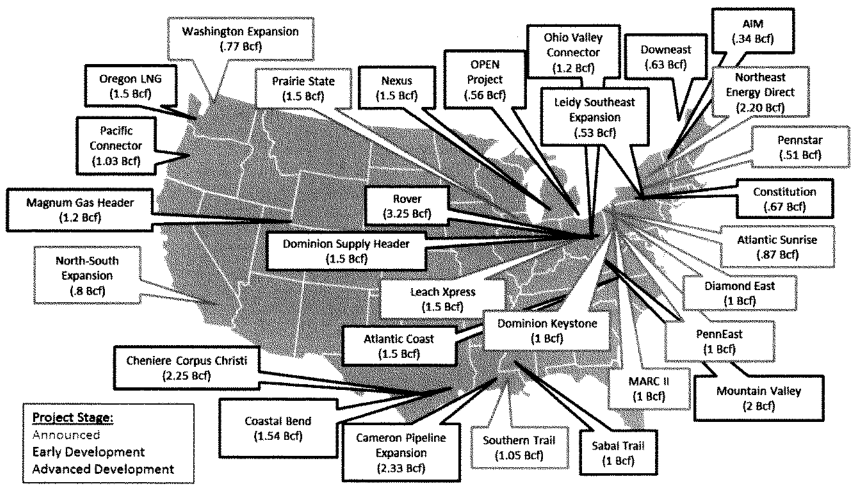
The Marcellus and Utica Shales, two of the most promising North American shale plays, hold potential not just for power generation, but for revitalizing our manufacturing base and natural gas exports. Fortunately, the expansion, adaptation and modification of pipelines to allow more gas movement both into and out of the Northeast producing region is growing, and expanding existing systems and building new systems to transport natural gas produced in the Northeast to consuming markets outside the region brings more supply to demand centers around the country. Pipeline companies are planning to modify their pipeline systems enough that 8.3 Bcf/d of Marcellus gas can be moved out of the Northeast to other consuming markets.[21] As an example, the Rockies Express Pipeline (REX) was one of the first pipelines to allow movement of Appalachian gas[22] from east to west. Recent enhancements to REX will provide approximately 1.8 Bcf/d of additional capacity by mid-2015 to western markets. There are also multiple interconnects on REX able to receive Appalachian gas from the mainline and transfer the gas to major industrial markets, such as Chicago and the Gulf Coast.[23]

Additionally, Columbia Gulf Transmission completed two bidirectional projects in 2013 and 2014 that enabled their system to transport natural gas from Pennsylvania to Louisiana. Likewise, the ANR Pipeline, Tennessee Gas Pipeline, Texas Eastern Transmission and Transcontinental Gas Pipeline, which all currently flow into the Northeast, are planning to become bidirectional. These projects will ultimately be capable of moving a total of 5.5 Bcf/d of Marcellus gas to the Gulf Coast, taking advantage of the potential industrial demand and LNG exports in that region.[24]

[21] EIA, "Today in Energy", last modified December 2, 2014, accessed May, 7, 2015, http://www.eia.gov/todayinenergy/detail.cfm?id=19011.
[22] Appalachian gas refers to natural gas from the Marcellus, Utica, and Devonian shale plays.
[23] EIA, "First westbound natural gas flows begin on Rockies Express Pipeline", last modified June 18, 2014, accessed May 7, 2015, http://www.eia.gov/todayinenergy/detail.cfm?id=16751.
[24] EIA, "Today in Energy", last modified December 2, 2014, accessed May 7, 2015, http://www.eia.gov/todayinenergy/detail.cfm?id=19011.

By better connecting Marcellus and Utica natural gas supplies to demand centers across the U.S., all regions will be able to benefit from this prolific regional supply, this includes more connection capacity to other producing regions. For example, Bentek Energy found that Southeast natural gas demand is expected to grow 8.5 Bcf/d by 2024.[25] Supplies from the Marcellus and Utica will be able to meet this growing demand through the new bidirectional capacity and incremental pipeline additions. This supply enables the revitalization of manufacturing, cleaner power generation and increased LNG exports.

Figure 5: Major Pipeline Projects in the U.S.



Source: SNL, ANGA

The economic benefits from linking producing regions to demand centers are profound. IHS found in 2012 that GDP contributions were $238 billion from upstream production activity, $39 billion from midstream and downstream activity and $7 billion from energy-related chemical activity. By 2025, IHS estimates that these GDP contributions will grow to $475 billion for upstream, $7 billion from midstream and downstream and over $51 billion from energy-related chemicals.[26] Robust infrastructure capacity provides the connection between supply basins and demand centers that will help unleash our nation's economic potential.

[25] Bentek Energy, "The Southeast: Major Natural Gas Demand, Supply and Infrastructure Coming Together 2014-2024," May 2014, 12.
[26] IHS, "America's New Energy Future, Volume 3: A Manufacturing Renaissance – Main Report," September 2013, 1.

Conclusion

As a result of innovative breakthroughs, the natural gas industry is able to access vast domestic natural gas resources. The accompanying significant growth in natural gas over the past decade has transformed us from a posture of energy scarcity to one of energy abundance. This shift has provided our nation with enormous economic, environmental and energy security benefits. However, to fully realize the potential presented by our natural gas abundance, it is imperative that we support natural gas infrastructure development in all regions of the United States.

This Congress has an unprecedented opportunity to advance our nation's economy, environment and energy security by strengthening our nation's natural gas infrastructure. We appreciate the opportunity to testify today and ANGA looks forward to working with you on important solutions as this legislative process moves forward. Thank you.

The CHAIRMAN. Thank you, Ms. Bowman.
Mr. Weisgall, welcome.

STATEMENT OF JONATHAN M. WEISGALL, VICE PRESIDENT, LEGISLATIVE AND REGULATORY AFFAIRS, BERKSHIRE HATHAWAY ENERGY

Mr. WEISGALL. Thank you. My name is Jonathan Weisgall with Berkshire Hathaway Energy. We own three regulated utilities that serve 5.3 million customers in 11 states.

In addition to our geothermal facilities which is how we started years ago, we have invested over $16 billion in the last decade in wind and solar projects in nine states.

I want to hit on three issues today.

The first is PURPA modernization. Among other things PURPA mandated utilities to buy renewable energy from QFs, qualifying facilities. 37 years later renewable energy is flourishing and we are among its strongest proponents. Our projects, however, have been driven by policies other than PURPA such as state renewable portfolio mandates, Federal tax incentives, technological improvements and stricter EPA air regulations.

PURPA as it exists today is imposing significant and unnecessary costs on utility customers. It requires utilities to buy energy from a QF regardless of need. PURPA contracts are not subject to the same resource planning and cost scrutiny as other utility decisions and they can cause operating inefficiencies and reliability issues because the host utility has no control over where they are sited or integrated into its system.

Let me give you a specific example. The long range plan for our PacifiCorp utility, approved by our state regulators, shows no need for additional generation until 2028. However over the next 10 years PacifiCorp must purchase 39 million megawatt hours under its PURPA obligations at an average price of $66 per megawatt hour. The average market price today is $38, 43 percent lower.

This means that our customers must pay $1.1 billion above market for PURPA mandated power they don't even need. And this is not an isolated example. Other Western utilities are facing similar dilemmas.

PURPA and the FERC implementing regulations have not kept pace with market changes. New imbalanced market structures and FERC's interconnection rules for smaller facilities now allow QFs of all sizes to compete in wholesale markets and utility competitive solicitations.

We have two suggestions for modernizing PURPA explained more fully in my written testimony.

The first is to expand the definition of comparable markets to include voluntary, auction based, energy imbalance markets as one that meet threshold competitive requirements so that utilities participating in these markets are relieved of PURPA's mandatory purchase obligation.

The second is to eliminate the rebuttable presumption in FERC Order 688 which established that QFs smaller than 20 megawatts lack access to competitive markets.

I urge you to consider these and other proposals that we and the Edison Electric Institute support.

Examples include Senator Risch's S. 1037 which would terminate the mandatory purchase obligation if a state determines that additional generation is not needed or a measure to prevent large QF projects from being divided into smaller ones to essentially gain what is called the FERC One Mile Rule.

My second issue covers transmission. Berkshire Hathaway Energy and Edison Electric Institute and many others have long supported measures to better coordinate Federal permitting and siting for interstate transmission projects on public lands.

Congress sought to improve the process in 2005 when it added Section 216H to the Federal Power Act giving the Department of Energy new Federal lead agency authority. That hasn't worked.

We believe the best way to improve Federal transmission siting and permitting is to enhance the role of FERC which, after all, already has this job in overseeing permitting of interstate natural gas pipelines.

We're pleased you're considering two bills in this area.

If you don't adopt S. 1017 which would transfer that DOE function to FERC, we do support your bill, Chairman Murkowski, S. 1217 which would codify the rapid response team for transmission and create a transmission ombudsman within FERC.

My third issue concerns the need to minimize cost shifting among customers. A growing number of whom are generating their own energy through distributed generation, DG. But these customers are still connected to the grid—when their DG systems generate more energy than they need the grid takes the excess. When their systems aren't generating, they of course, still need the grid. Proper rate structures and tariffs must be designed for these customers. For example, under so called net metering tariffs a customer can end up paying nothing towards a utility's fixed costs leaving non-solar customers to make up the difference.

We support Chairman Murkowski's S. 1219 which encourages state PUCs to examine cost shifting and determine whether net metering rates are just and reasonable and not unduly preferential or discriminatory.

The issue of rooftop solar has led to extreme rhetoric on all sides, but the issue is not pro-solar or anti-solar, it's about equitable cost allocation among all customers.

For customers who want to generate their own power the issue is how to accommodate them in the most cost effective manner that is fair to them and to other customers who do not and cannot generate their own power.

So in the end with proper rate design the utilities should be agnostic as to whether a customer generates its own power.

Thanks for the opportunity to share our views with you, and I look forward to answering any questions you may have.

[The prepared statement of Mr. Weisgall follows:]

STATEMENT OF JONATHAN M. WEISGALL
VICE PRESIDENT, LEGISLATIVE AND REGULATORY AFFAIRS
BERKSHIRE HATHAWAY ENERGY
BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
May 14, 2015

Introduction

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, thank you for the opportunity to appear before you today as you consider legislation to address challenges and opportunities to modernize U.S. energy infrastructure. My name is Jonathan Weisgall, and I am vice president for legislative and regulatory affairs at Berkshire Hathaway Energy. With our roots in renewable energy, BHE today owns three regulated U.S. utilities – MidAmerican Energy Company, PacifiCorp, and NV Energy – with customers in 11 states as well as other energy assets in the U.S., Canada, the U.K., and the Philippines – that collectively deliver affordable, safe, and reliable service each day to more than 11.5 million electric and gas customers and consistently rank high among energy companies in customer satisfaction.

A large part of our U.S. business strategy has been to invest in renewable energy and develop competitive transmission projects to meet electric reliability needs and existing and emerging clean energy goals. When current projects are completed, we will have invested approximately $8.0 billion in our wind energy portfolio among our regulated utilities in Iowa, Wyoming, Oregon, and Washington State. In addition, we have invested an additional $8.1 billion in just the last five years through our unregulated subsidiary, BHE Renewables, in three very large utility-scale solar projects as well as wind projects. And we continue to operate our 10 geothermal plants, some of which date back to the 1980s. In order to encourage the continued development of renewable energy resources at low costs to our customers and protect them from volatility in power costs, we have identified three areas that would benefit from Congressional action.

First, modernize the Public Utility Regulatory Policies Act of 1978, also known as "PURPA."

I. PURPA Background – Need for Change

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted to increase the country's energy independence, decrease reliance on foreign oil, and reduce dependence on fossil fuels by promoting increased energy efficiency. Section 210 directed the Federal Energy Regulatory Commission (FERC) to prescribe rules necessary to encourage cogeneration and small power production. Qualifying facilities (QFs) include cogeneration plants that use steam or heat generated from an industrial or commercial process to also produce electricity, and small power production facilities that are not more than 80 megawatts (MW) in size and use solar, wind, biomass, waste, or other renewable resources to produce electricity. Section 210 required

FERC to develop rules requiring utilities to purchase power from QFs, also known as the mandatory purchase obligation.

Current PURPA Provisions are Costly for Utility Consumers

Since 1978, PURPA has helped reduce U.S. dependence on fossil fuels by promoting energy efficiency and renewable resources. Renewable generation in the U.S. has increased significantly since PURPA's passage, substantially due to financial incentives in the tax code, state renewable portfolio standard requirements, stricter Environmental Protection Agency air emission regulations, and technological improvements. The continuation of the mandatory purchase obligation as it exists today, however, is imposing significant and unnecessary costs on consumers:

In many instances, the power produced by QFs is not needed to replace baseload generation or meet decreasing levels of demand.

Growth of electricity demand has slowed in each decade since the 1950s. Since PURPA's enactment, electricity markets have developed to allow utilities to purchase replacement power rather than build baseload plants. BHE's PacifiCorp utility is experiencing a significant increase in PURPA contract requests, despite the fact that its long-range resource plan shows no need for additional generation resources until 2028. It currently has requests for 3,641 MW of new PURPA contracts, in addition to the 1,732 MW of PURPA contracts that are already executed. The number of PURPA contracts may soon equal PacifiCorp's average retail load. For example, the 5,373 MW of existing and proposed PURPA contracts at their nameplate capacity would be equal to 79% of PacifiCorp's average retail load and 108% of PacifiCorp's minimum retail load.

State administrative decisions regarding long-term power purchase contracts have tended to over-estimate future market prices.

The mandatory purchase obligation requires QFs to sell to the interconnected local utility at a set price based on the utility's "avoided cost," regardless of whether the utility needs the generation or whether it is the most efficient resource choice. Avoided cost is the cost the utility would have incurred to produce or purchase the power elsewhere. Although avoided cost rates are theoretically intended to reflect actual costs to build or replace necessary generation to protect customers from paying other costs, in practice state "administrative" determinations, particularly for the long-term power purchase contracts that their vertically integrated utilities have typically been required to enter into to facilitate QF construction, have tended to over-estimate future market prices. These contracts, with up to 20-year terms, often assumed electric rates would continue to rise, an error that has required utility ratepayers to pay substantially above-market rates for power, even in instances where a utility's integrated or long-term planning process demonstrates that no new resources are needed for the foreseeable future. Left unchecked, the resulting subsidies will continue to unfairly shift these rising power costs to utility customers and undermine competitive wholesale electricity markets.

Long-term fixed-price contracts carry significant risk. For example, on August 1, 2014, a 10-year fixed-price contract for a 7-day by 24-hour electricity product at the Mid-Columbia

("Mid-C") wholesale power market trading hub was priced at $45.87 per megawatt-hour (MWh). On February 2, 2015, just six months later, that same 10-year contract was priced at $38.11 per MWh. The 10-year electricity market declined 17% in just six months. Over the next 10 years, PacifiCorp is under contract to purchase 38.9 million MWhs under its PURPA contract obligations at an average price of $66.32 per MWh. The average forward price curve for Mid-C during this same 10-year period is $38.11 per MWh, or a difference of $28.21 per MWh. Thus, the market price is 43% lower than the PURPA contract obligation price that PacifiCorp is forced to pay for this unneeded power. This means that PURPA-mandated power purchases – which our customers don't need – could cost PacifiCorp's customers an incremental $1.1 billion for the next 10 years above market prices. And PacifiCorp's experiences are far from isolated; many Western utilities are facing similar PURPA contracts.

PURPA contracts are not subject to the same planning and cost scrutiny as other resource decisions and thus expose customers to increased and unnecessary risks.

Many utilities, as required by state commissions, utilize an integrated resource planning (IRP) process to evaluate proposed energy contracts to ensure that any resource decisions are reasonable and prudent. The planning horizon for such resource plans typically is in the three-year range. PacifiCorp, for example, primarily enters into long-term transactions (those that exceed 36 months) only when there is a clearly identified long-term resource need in its IRP. Companies also utilize a rigorous request for proposal (RFP) process to acquire any long-term transaction or resource need identified in the IRP. Under PURPA, however, companies cannot refuse to execute PURPA contracts based on the price or the contract term, or whether the energy is needed, or based on other transaction parameters that would normally be the basis for rejection of other RFP contracts.

PURPA contracts do not go through the same competitive bid RFP process, including oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP. PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation under federal law.

The mandatory purchase obligation can cause operating inefficiencies and reliability issues on the host utility systems.

PURPA contracts can cause operating inefficiencies and reliability issues for the host utility, which has no control over where the QFs are sited or integrated into its system. Many QFs are "undispatchable" and might lead to over-generation conditions or inefficient use of baseload units that are forced to cut back operations to accommodate unscheduled QF purchases. Inefficient siting of large amounts of QF power can increase the need for otherwise unneeded transmission upgrades.

Open Access and Market Formation

Since 1978, substantial changes in the electric industry have removed the structural barriers to entry and opened up opportunities for new entrants, including QFs, to supply wholesale energy. FERC has imposed open access transmission tariff requirements and

standardized interconnection rules for small generators (20 MW or less) and large generators (greater than 20 MW). Thus, generators of all sizes have the right to interconnect to the local utility under a FERC-approved set of interconnection and transmission rules that apply to all generators on a non-discriminatory basis.

The industry has seen the formation of independently administered regional markets across the country for power producers to bid to supply energy, in day-ahead or real-time. Today, there are six regional markets now run by independent system operators (ISOs) and regional transmission organizations (RTOs), who also administer open access transmission tariffs that facilitate the availability of transmission and interconnection services to the grid for all entrants.

Energy Policy Act of 2005 (EPAct 2005)

In 2005, Congress recognized that these structural changes had reduced existing barriers to entry for QFs and that the mandatory purchase obligation, which imposed significant costs to consumers, was no longer necessary. Congress adopted Section 1253 of the EPAct 2005, adding Section 210(m) to PURPA, which provides for the termination of a utility's obligation to purchase power from QFs in its service territory after appropriate findings from FERC that a QF has nondiscriminatory access to one of three specified categories of wholesale markets. The three categories of markets under Section 210(m)(1) include:

(A) "Day 2 markets" (independently administered, auction-based day-ahead and real-time markets for the sale of electric energy and wholesale markets for long-term sales of capacity and electric energy);

(B) "Day 1 markets" (transmission and interconnection services that are provided by a FERC-approved regional transmission entity and administered pursuant to an open-access transmission tariff that affords nondiscriminatory treatment to all customers, and competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the QF is interconnected); and

(C) "Comparable markets" (for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as the two "Day 2" and "Day 1" markets described above).

FERC's Implementation of EPAct 2005

In 2006, FERC issued new rules to implement the new Section 210(m) to govern the removal of the mandatory purchase obligation. In Order No. 688 (and subsequent orders), FERC created a rebuttable presumption that QFs larger than 20 MW have nondiscriminatory access in the "Day 2 markets" of the then-Midwest (now Midcontinent) ISO, PJM, ISO New England, and New York ISO; in the "Day 1 markets" of Southwest Power Pool; and the "comparable markets" of the California ISO (CAISO) and the Electric Reliability Council of Texas (ERCOT). FERC allows QFs larger than 20 MW to rebut the presumption by showing they have no access due to

operational characteristics or transmission constraints. The evidentiary showings FERC established are higher for "Day 1 markets" than for "Day 2 markets" and highest for "comparable markets" due to the presumption that QFs there have fewer off-system sales opportunities respectively in these markets. FERC also established a rebuttable presumption that QFs smaller than 20 MW lack nondiscriminatory access to the three 210(m) markets unless a utility makes a facility-specific showing that each small QF has access. This presumption has made it exceedingly difficult for utilities to avoid purchasing from QFs, which could be as large as 20 MW, without limit, and regardless of whether the power is needed.

In applying Order No. 688, FERC has routinely terminated the mandatory purchase obligation from QFs greater than 20 MW in organized "Day 2 markets," but, with limited exceptions, denied the same relief with respect to small QFs. FERC has thus far not terminated the mandatory purchase obligation for any utility operating outside an organized market and, other than ERCOT and CAISO, has not found any "comparable markets" to exist. Only utilities that have transferred control over their transmission systems to a FERC-approved ISO/RTO have satisfied FERC's market structure termination criteria. While FERC has continued to encourage utilities to join ISO/RTOs, participation remains voluntary. Thus, there has been no relief from the mandatory purchase obligation for utilities that have determined that joining an ISO/RTO is not in the best interest of their customers.

II. Suggested Legislative Reforms

As detailed above, PURPA – and FERC's implementing regulations – have not kept pace with wholesale market evolutionary changes. Developments such as new energy imbalance market structures as well as FERC's imposition of standardized interconnection rules and procedures tailored for smaller facilities have effectively removed any remaining structural barriers to entry and opened up opportunities for new entrants, including QFs, to supply wholesale energy to distant markets whether the host utility is in an ISO/RTO or not. BHE and our trade association, the Edison Electric Institute, believe that PURPA needs to be modernized to recognize these changes and protect a broader group of utility customers from unnecessary costs and inefficiencies.

Toward that end, BHE has proposed a legislative suggestion for modernizing PURPA and removing its harmful elements for utility customers, while recognizing the changed circumstances facing QFs today since the EPAct 2005 Section 210(m) provisions were adopted (*See* Attachment A - Text of Proposed PURPA Modernization Legislation). As outlined below, these statutory changes ensure that utility customers are not harmed by unnecessary purchases of QF power and promote further regional wholesale market development by updating PURPA to recognize the vast new opportunities that QFs of all sizes have today to compete in wholesale electric markets and utility competitive solicitations for both short-term and long-term energy and capacity sales. BHE's proposed PURPA modernization amendment has three main elements:

(1) Expand "comparable markets" under Section 210(m)(1)(C). The proposed amendment revises the "comparable markets" section to specifically include voluntary, auction-based energy imbalance markets as the type of markets that meet the threshold market

requirement in the existing law, so that utilities participating in those markets are relieved of PURPA's mandatory purchase obligation.

This change would update the statute to recognize the vast new opportunities that QFs of all sizes have today to compete in wholesale electric markets for both short-term and long-term energy sales. This includes the voluntary, 5-minute Western EIM that CAISO and PacifiCorp launched in November 2014, which currently includes portions of California, Idaho, Oregon, Utah, Washington, and Wyoming and will soon add much of Nevada when our NV Energy utility joins the EIM in October 2014. The independently administered EIM now provides a broader range of QFs a meaningful opportunity to sell electric energy, including short-term energy sales, to buyers other than their interconnecting electric utility, and provides access to a real-time wholesale market of comparable competitive quality as a "Day 2 market."

By including energy imbalance markets, such as the Western EIM, in the type of markets that meet the comparable markets standard, the proposed amendment will encourage the expansion of the EIM by attracting additional utility participants and new buyers and sellers. Such expansion will yield even further expanded market opportunities for QFs and even greater savings for customers, more efficient deployment of intermittent renewable energy resources, and enhanced operational and reliability benefits for the Western grid. The amendment also recognizes that eligibility for termination of a utility's QF purchase obligation under PURPA should not be effectively tied to that utility joining an ISO/RTO as a participating transmission owner, when doing so may not be in the best interest of its customers.

(2) <u>Eliminate the 20-MW size demarcation for presumption of access to markets</u>. The proposed amendment makes clear that QFs of any size are presumed to meet the access requirement to the relevant markets, if the QFs are eligible for service under FERC-approved Open Access Transmission Tariff and interconnection rules in the relevant market <u>and</u> the QF is able to participate in competitive solicitations overseen by a state regulatory authority.

Order No. 688 drew the line between large and small QFs in 2006 based on the circumstances existing at that time. Today, with the creation of FERC-mandated standardized interconnection rules and procedures tailored for smaller facilities, open-access transmission and market access is available to small and large QFs and FERC's existing size distinction is no longer warranted. Eliminating the existing 20-MW size threshold would benefit utility customers, as they are harmed by unnecessary purchases of QF power regardless of whether those purchases are from multiple smaller QFs or a single larger QF. Updating the statute also recognizes the meaningful opportunities QFs of all sizes now have today to sell capacity, including long-term and short-term sales, and electric energy, including long-term and short-term sales, to buyers other than their interconnecting electric utility to the extent QFs can participate in competitive solicitations overseen by a state regulatory authority. Today, such processes are increasingly being used to allow QFs and other independent producers to compete with the incumbent utility to supply capacity and energy needed by the utility consistent with its state-sanctioned IRP process. Such competitive solicitations provide QFs access to a wholesale market of comparable competitive quality as a "Day 2 market."

(3) Requires FERC to revise its regulations. The proposed amendment directs FERC to revise its regulations, such as Order No. 688, within 120 days to incorporate the changes.

Finally, BHE urges Congress to consider these and other PURPA modernization proposals offering relief to utilities from the current mandatory purchase obligation that we and our trade association, the Edison Electric Institute, support. Examples include S. 1037, which would tie termination of the purchase obligation to a state determination that additional generation resources are not needed, or proposals to create a rebuttable presumption targeting PURPA gaming created by FERC's "one mile" rule. Our utilities commonly see larger projects divided into smaller QF projects to game the "one mile" rule and capture higher PURPA prices at the expense of customers.

A second area benefiting from Congressional action is improving the federal transmission permitting, siting, and review processes.

As the largest transmission owner in the Western U.S. and an active developer of several high-voltage transmission projects spanning multiple states and federal lands, BHE has long supported measures to better coordinate the existing federal permitting and siting processes for major electric transmission projects on public lands to reduce the uncertainty for project applicants and to streamline the approval process. Reforming current federal permitting and siting processes is one of the Edison Electric Institute's top priorities in federal energy legislation.

Additionally, as part of its ongoing effort to permit and site its multi-state Energy Gateway transmission project, among the nation's largest currently in development, our PacifiCorp utility has first-hand experience participating in the Administration's Interagency Rapid Response Team for Transmission (RRTT), and most recently, outreach sessions as part of the Administration's Quadrennial Energy Review development process. BHE offers the following observations and legislative recommendations with the above experiences and perspectives in mind.

First, undue delays in obtaining federal regulatory permits only serve to postpone the construction of needed transmission projects and the clean energy, reliability and other benefits such projects provide for customers. In order to continue developing America's vast renewable energy resources and delivering them to customers, and maintaining an efficient and reliable electric grid, completing such transmission projects on a timely basis will be essential. Without PacifiCorp's Energy Gateway and other regional transmission projects on public lands, there will be no means to transport adjacent renewable generation to distant load centers. As a result, some of our nation's largest and best clean energy resources will remain unable to contribute as they wait for transmission lines to be sited and built. The most critical path item to achieving this objective is schedule predictability within the federal permitting process. We believe substantial process improvements, once realized, will deliver significant benefits to the nation's utility customers who depend upon adequate, reliable, and reasonably-priced electricity to carry on their daily business, and will support vital economic growth across the country. The greatest

efficiencies to be gained are through better National Environmental Policy Act (NEPA) execution and, accordingly, BHE recommends that Congress focus on improving that part of the federal permitting and siting process.

Second, BHE appreciates that Congress sought to improve the federal transmission siting process in 2005 when it added new Section 216(h) to the Federal Power Act giving the Department of Energy (DOE) new lead agency authority to coordinate the approval of all required federal authorizations and related environmental reviews for transmission projects on public lands. While it has been helpful to have a lead coordinating agency, DOE's performance frankly has not met industry expectations, nor is it producing the positive impacts envisioned by Congress. Fairly or not, DOE's critical 216(h) responsibility has simply been eclipsed by other departmental priorities. Importantly, the lone rulemaking Congress charged DOE with promulgating under 216(h) role was originally proposed in 2008, revised again in 2011, and has still yet to be finalized, and the DOE position to implement 216(h) has been vacant for over 18 months. Given DOE's track record and the successful role FERC continues to play as the lead agency responsible for permitting and siting interstate natural gas pipelines, BHE continues to support transferring the DOE's Section 216(h) lead agency coordinating authority to FERC, which we believe would better ensure that comparable electric transmission projects are permitted in a synchronized and timely manner.

Third, BHE similarly appreciates the continuing efforts of DOE and the RRTT in developing streamlined and coordinated approaches to the permitting and siting of transmission projects on federal lands. The Administration's related RRTT reform effort, launched by DOE in October 2011 with the targeting of seven national priority transmission lines, including PacifiCorp's Gateway West project, was unquestionably a step in the right direction. Unfortunately, in the eyes of PacifiCorp and other project sponsors, the RRTT process, too, has fallen short of expectations, producing precious few success stories to date beyond improving the coordination among the federal agencies involved in project NEPA analysis. By all accounts the RRTT has not measurably accelerated the permitting of any lines or moved projects' NEPA process any faster, let alone provide project proponents the schedule predictability they desire more than anything. To a company, project sponsors have been hard pressed to point to direct, positive ways in which the RRTT solved specific organizational accountability and other problems, let alone accelerated their project timelines.

Fourth, against the backdrop above, to meet national policy goals, BHE and the Edison Electric Institute both encourage Congress to intervene again and ensure that the efficiency and effectiveness of multiple agency reviews and decisions on major transmission projects is improved, and the uncertainty with federal cooperating agency reviews is reduced so that needed transmission expansion can keep pace with the nation's revolving resource mix that is being driven by a rapidly changing policy landscape. Congress should takes steps now to ensure that the federal RRTT agencies provide the schedule certainty lacking today and assign clear accountability within the cooperating agencies to deliver NEPA milestones on reasonable fixed timeframes. Similar measures are needed to ensure that national energy policies are infused into staff-level decisions and federal agency management must create feedback loops to obtain confidence that field staff is implementing their duties in light of current policies. Each of these recommendations, if adopted, would have the salutary effect of facilitating the timely release of

critical environmental review documents and mitigating the permit schedule uncertainties facing project sponsors by averting the potential for conflicting federal policy objectives.

Based on our PacifiCorp utility's experience trying to site and permit its multi-state Gateway West transmission project, the more time the Bureau of Land Management (BLM) takes to resolve route controversy on private and federal lands, the more apt the agency is to adopt alternative routes for inclusion in the Environmental Impact Statement (EIS), delaying a project, which in this instance is critical to the development of additional renewable energy resources in various Western states. In fact, delays continue today, seven years after the Gateway West Public Scoping. For the project's final two segments, the BLM has initiated an additional two-year supplemental EIS process to look at even more alternative routes, meaning PacifiCorp may not receive a Record of Decision (ROD) until sometime in 2016, nearly 10 years after it filed an application with the BLM for an easement across federal lands. This is unacceptable.

Further, by taking more time, not only do more alternatives come into play, but the federal agencies are continually adopting/developing/changing policies, manuals, and instructions that require additional analysis and create new compensatory mitigation requirements for projects that have been in permitting for many years. These projects don't get "grandfathered." This is occurring on PacifiCorp's Gateway South project with regards to sage grouse, lands with wilderness characteristics, and new conservation easements funded by the Natural Resource Conservation Service – U.S. Department of Agriculture.

Above all, federal agencies must be required to truly work together to assure consistent application of permitting requirements and clear communication of requirements between field/state/federal agency headquarter levels prior to the start of the permitting process and throughout the process. PacifiCorp's experience has been that the above structure has worked fairly well where it has been implemented, *e.g.*, on PacifiCorp's Sigurd-to-Red Butte segment. This practice needs to be made a federal priority so the benefits can be more broadly realized. BHE believes it is reasonable for the federal lead agency to complete the NEPA process from right-of-way (ROW) application to the ROD and the ROW grant within three to four years. Schedule certainty is as critical if not more important than any actual benchmark.

Finally, as this Committee considers key elements of a comprehensive, bipartisan energy package, BHE would hope you put further federal coordination around transmission permitting and siting on the list as a top priority, with the goal of assuring consistent and expedited treatment of transmission projects requiring interagency and intergovernmental coordination. We strongly support enhancing FERC's statutory role in facilitating improved federal permitting processes. As an independent federal agency charged by Congress with promoting the development of safe, reliable, secure, and efficient energy infrastructure, we believe FERC could bring a fresh perspective and critical focus to boost the other RRTT agencies' abilities to dramatically improve the overall quality and timeliness of their existing federal permitting processes. We were pleased to see that two legislative proposals have been offered to that end. In the event Congress opts not to adopt the approach suggested by Sen. Heinrich (D-NM) in S. 1017, which would fully transfer DOE's Section 216(h) authority directly to FERC, we'd support enactment of Chairman Murkowski's own approach, S. 1217, which would enshrine the RRTT in law and create a Transmission Ombudsperson within FERC to help address interagency

issues or delays on permits and complaints from parties involved in electric transmission infrastructure permit applications. Either approach would be a marked improvement of the current state of affairs.

The third area benefiting from Congressional action is encouraging States to minimize cost-shifting among customers.

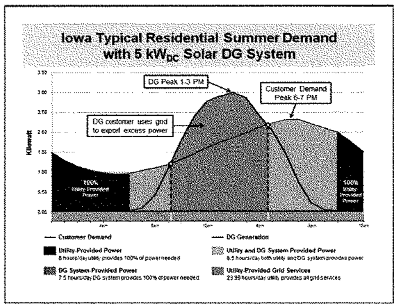
After a significant period of relative stability, the energy industry is evolving rapidly. New issues like distributed generation, electric vehicles, smart grid, energy storage, advancements in wind and solar technology, flat load growth and increasing environmental regulation, necessitate changes in the way we do business. We are positioning our company to be sustainable in this changing energy marketplace and changing the ways we do business to provide better value for our customers.

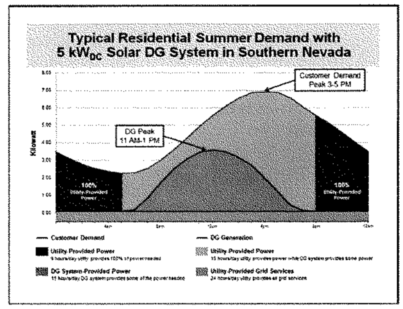
A Different Type of Customer, But Still Dependent on the Grid

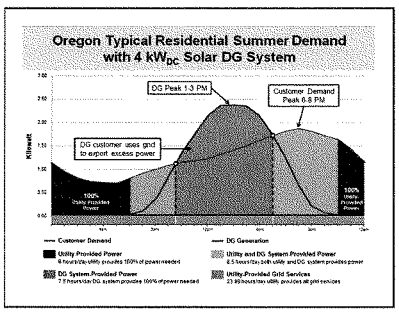
A growing number of our customers, both commercial and residential, are interested in generating their own power, through the installation of distributed generation. It's our responsibility to help our customers understand this option, because nearly all of the distributed generation customers will still be connected to our utilities' electrical grid. When their distributed generation systems generate more power than they need, they need the electrical grid to distribute the excess power. And, when their distributed generation systems aren't generating power – for example with a rooftop solar system, when the sun sets – they will still rely on the utility to provide them with power services. They rely upon the grid all the time for reliability, for example, using the grid to help start air conditioners, refrigerators and motors even when they produce their own power.

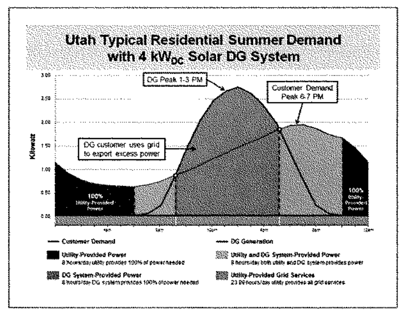
As distributed generation becomes an option for more consumers, three important things must be considered. First, distributed generation can be costly in comparison to utility scale generation. For example, although the cost of solar power has been declining steadily, the cost of utility scale solar continues to be about half of the cost of distributed solar. This is due largely to economies of scale. It is less costly to install one 4 MW unit than 1,000 4Kw units. All customers can benefit from utility scale solar and these systems can be integrated into utility control and dispatch processes.

Second, today's distributed generation systems cannot function without the grid, nor can they fully meet the customer's electricity needs. For example, in the case of rooftop solar the following graphs illustrate the customer demand for electricity in different states over the course of a typical summer day (red line) and the power being generated by a rooftop solar distributed generation system (dark blue line). The orange shaded area shows the number of hours during the day the utility and the distributed generation system provide power. The blue shaded area shows the hours during the day when the distributed generation system provides for the residential customer's power needs, and during some hours produces excess power that is distributed by the utility.









Third, utility grid services are needed 99.99% of the time to ensure power needs are met reliably and safely. The tan-shaded area along the bottom of each graph shows the utility provides all grid services 23.99 hours a day. Power is delivered through the utility's system to distributed generation customers on cloudy days, at night, when the customer's system is not functioning properly, and even on hot, sunny days when solar panels may not meet all of the residential customer's power needs.

Distributed Generation Customers Still Need the Grid's Instantaneous, Start-Up Power

It will almost never be true that the power produced by distributed generation customers' system will exactly match their power needs. At any time, grid services are needed to meet the customer's power needs or to transport excess power to the utility. Startup of some appliance motor loads (e.g., air conditioner, refrigerator, washing machine) requires supplemental power beyond what a distributed generation system can provide. For example, when a central air conditioning system starts, a distributed generation system that otherwise meets all of the customer's energy needs may need additional power from the utility to allow the system to start.

The need for instantaneous power is summarized well by the Electric Power Research Institute:

"The grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current ("in-rush" current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without grid connectivity or other supporting technologies, a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current." *See*, "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources," Electric Power Research Institute (February 10, 2014).[1]

Distributed Generation Customers Use the Grid to Ensure Reliability

The utility must have stand-by or backup power on hand to instantaneously serve customers, when the output from solar and wind generators is fluctuating, for example when clouds pass by or wind speed declines and then picks back up again. This resource variability creates uncertainty and can disrupt local grid system planning, causing a notable increase in generation re-dispatch events causing the grid to rely on the utility's generating resources to offset the decline in solar or wind power production. Having these utility spinning reserves available to deal with intermittency incurs additional costs and with retail net metering, customers with distributed generation do not pay for them.

As described in the Electric Power Research Institute report discussed earlier:

"The grid serves as a reliable source of high-quality power in the event of disruptions to [distributed energy resources]. This includes compensating for the variable output of [photovoltaic] and wind generation. In the case of [photovoltaic], the variability is not only diurnal, but as shown in Figure 5, overcast conditions or fast-moving clouds can cause fluctuation of [photovoltaic]-produced electricity. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons— to offset variable and uncertain output from distributed resources. Through instantaneously balancing supply and demand, the grid provides electricity at a consistent frequency. This balancing extends beyond real power, as the grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation." *See*, "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources," Electric Power Research Institute (February 10, 2014).

Distributed Generation's Two-Directional Power Flow Requires Changes to the Grid

People think a distributed generation system is less dependent upon the grid; however, distributed generation systems actually become more dependent on the grid. In fact, these systems require power to flow in two directions versus just one, which is how the grid system was initially designed.

According to a recent Massachusetts Institute of Technology Report:

[1] See, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733

> "Introducing distributed [photovoltaic] has two effects on distribution system costs. In general, line losses initially decrease as the penetration of distributed [photovoltaic] increases. However, when distributed [photovoltaic] grows to account for a significant share of overall generation, its net effect is to increase distribution costs (and thus local rates). This is because new investments are required to maintain power quality when power also flows from customers back to the network, which current networks were not designed to handle. [Emphasis added] Electricity storage is a currently expensive alternative to network reinforcements or upgrades to handle increased distributed [photovoltaic] power flows." *See*, "The Future of Solar Energy", MIT Energy Initiative (May 5, 2015).[2]

Initially, this change could adversely impact the distribution system requiring new investments in infrastructure. Voltage swings triggered by unpredictable fluctuations in output can potentially damage utility equipment and residents' home appliances; increase overall cost of maintaining the grid; require continued installation of larger, more expensive alternatives; and could even contribute to distributed outages.

> "With the current design emphasis on distribution feeders supporting one-way power flow, the introduction of two-way power flow from distributed resources could adversely impact the distribution system. One concern is over-voltage, due to electrical characteristics of the grid near a distributed generator. This could limit generation on a distribution circuit, often referred to as *hosting* capacity. Advanced inverters, capable of responding to voltage issues as they arise, can increase hosting capacity with significantly reduced infrastructure costs." *See*, "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources," Electric Power Research Institute (February 10, 2014).

New Two-Directional Communications Technology Needed to Ensure Reliability

Utilities will need a robust, sophisticated, two-directional communications technology that allows them not only to monitor what is happening with the distributed generation systems and the grid, but what to do about it when they experience operational issues associated with high levels of distributed generation penetration. Utilities may know where all that distributed generation is, but do not necessarily know how much electricity it is producing at any given time. That creates a huge "shadow load" that utilities cannot see, but which can affect operations. California is leading the way and will soon require "smart" functionality for all inverters that connect all solar to the grid.[3] Small-scale solar inverters will be required to perform specific automated and autonomous grid-balancing functions they don't perform today -- including several that aren't allowed under the current national standards that regulate grid-connected devices. Smart inverters could also be a low-cost way to mitigate the voltage changes caused by the fluctuating wind and solar generation, thus preventing potential power quality problems.

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[2] See, http://mitei.mit.edu/futureofsolar
[3] See, "Rule 21 Smart Inverter Working Group," California Energy Commission (http://www.energy.ca.gov/electricity_analysis/rule21/index.html)

Addressing Unfair Cost-Shifting

Today there are policies that do not require everyone to pay the same for grid services. For example, net metering is a policy that allows distributed generation customers to pay only for the power they do not make themselves (net power). When a distributed generation customer reduces their net usage from a utility (sometimes completely), the amount they pay for the grid services they use is significantly reduced because utilities recover most of the fixed costs of the distribution system in the volumetric charge for each unit of electricity their customers use. This is true even though the grid services are still needed all of the time – either to deliver power to the distributed generation customer or to deliver excess power from the distributed generation system to the utility as well as provide other critical services that are essential to operation of the grid, including voltage and frequency control. As a consequence non-distributed generation customers must pay for more of the grid services costs that are being used – but not paid for – by distributed generation customers. As the amount of distributed generation connected to the system grows, this unfairness will cause more costs to be shifted to non-distributed generation customers through higher rates.

As described by Harvard Professor Ashley Brown:

> "Retail net metering overvalues both the energy and capacity of solar [distributed generation], imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent consumers." *See*, "Valuation of Distributed Solar: A Qualitative View" by Ashley Brown, Harvard Electricity Policy Group (December 2014).[4]

As with PURPA, the challenge here is that state electric rate regulation and ratemaking need to adapt to changes in the industry. Rate structures and tariffs are currently not designed for a rapidly growing new class of customers who generate their own power using distributed generation. For example, the fixed costs of generating electricity, maintaining transformers, keeping up underground and above-ground lines along with all the other parts of the electric grid today are borne by the customers largely through the volume of their electricity purchases, which is commonly referred to as "a volumetric charge." So-called net metering programs or tariffs shift these fixed grid costs, which are not recovered through a separate rate design other than a volumetric charge, to non-solar customers, because rooftop solar customers aren't buying as much electricity.

As described in the Massachusetts Institute of Technology report discussed earlier:

> "In an efficient and equitable distribution system, each customer would pay a share of distribution network costs that reflected his or her responsibility for causing those costs. Instead, most U.S. utilities bundle distribution network costs, electricity costs, and other costs and then charge a uniform per-kWh rate that just covers all these costs. When this rate structure is combined with net metering, which compensates residential [photovoltaic] generators at the retail rate for the electricity they generate, the result is a

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[4] See, http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%2011.14.pdf

subsidy to residential and other distributed solar generators that is paid by other customers on the network. This cost shifting has already produced political conflicts in some cities and states — conflicts that can be expected to intensify as residential solar penetration increases."

"Because of these conflicts, robust, long-term growth in distributed solar generation likely will require the development of pricing systems that are widely viewed as fair and that lead to efficient network investment. Therefore, research is needed to design pricing systems that more effectively allocate network costs to the entities that cause them." *See,* "The Future of Solar Energy", MIT Energy Initiative (May 5, 2015)

Looked at another way in the context of the avoided cost standard of PURPA, utilities pay distributed generators the retail price for power, which includes the cost of electric energy as well as the fixed costs of delivery. The cost of the electric energy is the avoided cost. Since utilities are not purchasing delivery services from generators, this portion of their payment represents an amount in excess of "avoided cost." This amount can be 50 to 60% of the retail rate. The difference is paid by other customers, effectively serving as a cross-subsidy for the distributed generation.

Addressing unfair cost-shifting means states need to revisit electricity rate design. Utility distribution operations also need to be redesigned to manage these "transactive loads" between the utility and customer generators at the micro-grid scale. Every customer who generates their own power should be compensated at a fair rate for the excess power they sell and they should pay a fair price for use of the grid services upon which they rely. The system can be fixed in a way that creates fair rates for everyone who uses the poles, wires and underlying electricity generating assets.

Three-Component Rates

An equitable solution to the cost-shifting discussed above is through the design of three part rate structures in state regulatory or legislative processes. Berkshire Hathaway Energy is already actively participating in regulatory and legislative conversations on this issue at the state and federal levels. We support the use of three-component rates for sales to distributed generation customers consistent with the cost of serving these "partial requirements" customers. The three components are a customer ($/monthly bill) charge, a demand (kW) charge, and a power (kWh) charge. The three-component rate design has been used for decades to serve commercial and industrial customers and is familiar to regulators, but has not been common for residential customers because they historically did not produce their own electricity. Costs should be assigned among the components as nearly as practicable to reflect cost causation.

Incentivizing Smart Distributed Generation

Revisiting rate design also does not have to be one-sided. Customers with rooftop solar distributed generation systems will also benefit. For example, rooftop solar customers should be incentivized to move their system output closer to the utility power demand peak by installing western-facing modules to catch more late evening sun, instead of installing south-facing modules which may generate more power throughout the day, but not help with the afternoon

power demand peak on the utility's system. As a result, rooftop solar customers with western-facing modules that help lower the utility system's peak demand could avoid some demand charges for their power output.

A report by the Regulatory Assistance Project explains this opportunity:

> "It is now generally accepted that orienting solar panels to the west-southwest increases the output during the afternoon hours, while reducing output during morning hours. This would produce a more valuable profile of power output, better suited to the shape of load to be served ... With time-varying rates, consumers will realize greater value from their [photovoltaic] investment by installing racking to orient the panels toward the west. Properly designed, this should compensate customers for any slight reduction of total [photovoltaic] output that results from this strategy – a significantly higher price per kWh for the same or slightly lower output." *See*, "Teaching the Duck to Fly" by Jim Lazar, Regulatory Assistance Project (January 2014).[5]

The Need to Work on Behalf of All Customers

Our utilities need to work with all of our customers to ensure the changes that result from distributed generation are managed effectively, so that we can continue to deliver safe, reliable and fairly priced power for all customers when they need it. That is why BHE supports Sen. Murkowski's (R-AK) proposal, S. 1219, because it encourages state utility commissions to examine cost shifting and determine whether the rates established for net metering services are "just and reasonable" and "not unduly preferential or discriminatory."

The issue of rooftop solar has led to extreme rhetoric on all sides. But the issue is not pro-solar or anti-solar, but fundamentally about equitable cost allocation among all customers, those with and without distributed generation. For customers who want solar power, the issue is how to provide it and interconnect them in the most cost-effective manner that is fair to them and to the utility's other customers who do not or cannot take advantage of solar. A 2008 study by the National Renewable Energy Laboratory (NREL) found that only 22 to 27% of residential rooftop area is suitable for hosting an on-site rooftop solar system.[6] In the end, with proper rate design, recovery of fixed costs to maintain the grid should be assured so the utility may be agnostic as to whether a customer opts to install distributed generation.

Finally, we oppose Sen. King's (I-ME) S. 1213, the "Free Market Energy Act," as does the Edison Electric Institute. The proposed bill would expand federal jurisdiction over state electric distribution matters under which federal law currently preserves for state regulation. The bill establishes market rules that perpetuate preferences for small generation resources at the distribution level and are more costly than larger, utility-scale generation resources interconnected to the transmission grid. For example, Section 5 would amend Section 111(d) of PURPA to require state commissions and unregulated utilities to consider whether to apply the benefit(s), if any, with no mention of the cost associated with distributed generation for locational two-way valuations of time-of-use and/or real-time pricing for distributed energy

[5] See, http://www.raponline.org/search/site/?q=teaching%20the%20ducks%20to%20fly

[6] See, "Supply Curves for Rooftop Solar PV-Generated Electricity for the United States," National Renewable Energy Laboratory (Nov. 2008) http://www.nrel.gov/docs/fy09osti/44073.pdf

resources. While we are supportive of states and utilities taking up the subject, the bill explicitly authorizes compensating distributed generation providers for "the social value of distributed energy resources." Payment of compensation for "societal benefits" is a huge step away from the cost-based or market-based principles traditionally used in electricity markets.

Section 6 would also vastly expand the scope of QFs under PURPA that are eligible to make mandatory sales to utilities at government-set prices. It allows QFs to receive rates above avoided cost. States would have to consider setting this new category of mandatory purchases from distributed generators at the utility's full retail rate. It does not make economic sense to force customers to pay higher prices for excess distributed generation power when larger scale power that interconnects to the transmission grid can produce the identical benefits at a much lower cost.

Finally, Section 6 would also limit payments to help cover the fixed costs of the distribution grid to no more than $10 per month regardless of the true cost. Because the fixed costs of the grid are usually far greater than $10 per month, this provision shifts the balance of under collected fixed costs incurred to serve distributed generation customers to other customers using the grid.

Attachment A – BHE Text of Proposed PURPA Modernization Legislation

The proposed amendment, which would amend Section 1253 of the Energy Policy Act of 2005 (adding Section 210(m) to PURPA), reads as follows:

PURPA Section 210
16 U.S. Code § 824a–3 – Cogeneration and small power production

(m) Termination of mandatory purchase and sale requirements
(1) Obligation to purchase

After ~~August 8, 2005~~[insert date], no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

(A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and **(ii)** wholesale markets for long-term sales of capacity and electric energy; or

(B) (i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and **(ii)** competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are~~, at a minimum,~~ of comparable competitive quality as markets described in subparagraphs (A) and (B). For purposes of this subsection, any independently administered, voluntary, auction-based energy imbalance market, shall, by itself, be considered a market of comparable competitive quality as the markets described in subparagraphs (A) and (B), regardless of whether an applicable electric utility participating in such markets is a member of a regional transmission organization or independent system operator.

(D) For purposes of this subsection, qualifying facilities of any size are presumed to have nondiscriminatory access to wholesale markets described in subparagraphs (A) (B) or (C) above, if the qualifying facility in the relevant market (i) is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, and Commission-approved interconnection rules; and (ii) can participate in competitive solicitations overseen by a state regulatory authority.

The CHAIRMAN. Thank you, Mr. Weisgall.

Ms. Ericson, welcome.

STATEMENT OF AMY ERICSON, PRESIDENT, ALSTOM INC.

Ms. ERICSON. Good morning, Chairwoman Murkowski, Ranking Member Cantwell and distinguished members of this Committee. I'm Amy Ericson, President of Alstom, Inc. I appreciate the opportunity to testify at today's hearing.

Alstom is a technology developer across the power generation, transmission and distribution sectors. We've served the U.S. power industry for over 100 years, and Alstom Grid has been active in the U.S. grid software technology sector for more than 35 years.

Our grid business employs approximately 1,100 people in the U.S. with over 500 of those at our global smart grid center of excellence in Redmond, Washington.

The U.S. electric industry is undergoing a transformation unlike anything that we've experienced in the past 100 years. This transformation will create opportunities to enhance reliability, efficiency, resiliency and flexibility of the electric system as well as strengthen our nation's global competitive advantage.

I would like to highlight the role we play as a technology provider and touch on key trends driving change in the industry. These include an aging grid infrastructure which must respond to the challenges of a changing energy mix with the growing use of natural gas, renewable energy and distributed energy resources including energy storage as well as the need for increased resiliency to respond to severe weather events.

The first step in developing technology is to listen carefully to our customers which include America's electric utilities and regional transmission organizations and independent system operators. We must thoroughly understand their needs, their expectations and their challenges.

When it comes to power supply our customers consistently cite three must have requirements, reliability, affordability and sustainability. As we look forward we also see a clear need for more flexible and adaptable power system capable of meeting evolving requirements.

To be truly transformational and create an interconnected 21st century grid public and private partnerships are essential to the continuation of extensive R and D and the expansion of pilot projects to test and prove out cutting edge concepts. That's why Senator Cantwell's Grid Modernization legislation is so important; however, I do want to underscore that we can make great strides in modernizing the grid even today, and we see this from coast to coast.

We need to begin with the basics, for example, upgrading from older analog systems to state of the art digital technology. This will build the foundation for application of the advanced smart grid technologies currently in demonstration. We should not wait to begin the upgrades as this is an incremental process that will take time to implement.

The digital technology we provide enables electric utilities, RTOs and ISOs to manage this change which in turn benefits the consumers. Deployment and advancement of smart grid technologies

should be our first priority. It represents a set of critical, enabling technologies that can reduce the challenges associated with modernizing the grid and optimizing our electric systems.

Smart grids give utility operators greater visibility, greater operational flexibility and reliability allowing them to make rapid system responses to changing circumstances in their electric system. Smart grids also give consumers real time information on their energy usage allowing them to make informed decisions. Additionally smart grids are key to the seamless integration of distributed and renewable energy resources, perhaps the most significant trend we're seeing today.

The DOE has noted that weather related grid disruptions have doubled between 2000 and 2014 highlighting the need for hardening the grid. Smart grid and microgrid innovation can improve grid resilience and speed power restoration.

We strongly support Senator Cantwell's proposal because it reinforces the strong partnership between the public and private sectors in delivering a more modern grid. In addition the legislation provides tools for states to conduct analysis of their changing energy mix, develop performance metrics and assist in distribution planning.

In conclusion, Congress has an important role to play in advancing the modernization of our nation's electric grid. The public/private technology collaborations that would result from Senator Cantwell's bill will drive economic growth, strengthen our nation's global competitiveness and create highly skilled jobs.

Chairwoman Murkowski, Ranking Member Cantwell, thank you for this opportunity to testify today and I look forward to answering your questions.

[The prepared statement of Ms. Ericson follows:]

TESTIMONY OF AMY ERICSON,
PRESIDENT, ALSTOM INC.
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
HEARING ON ENERGY INFRASTRUCTURE LEGISLATION
May 14, 2015

Good morning Chairwoman Murkowski, Ranking Member Cantwell and distinguished Members of this Committee. I am Amy Ericson, President of Alstom Inc. I appreciate the opportunity to testify at today's hearing. Alstom is a technology developer in power generation, transmission and distribution and passenger rail. We have 93,000 employees worldwide, with 7,000 in the United States.

Alstom has served the U.S. power industry for over 100 years; Alstom Grid has been active in the U.S. grid software technology sector for more than 35 years. Our Grid business employs approximately 1,100 people in the United States with over 500 of those at our Global Smart Grid Center of Excellence in Redmond, Washington.

Alstom Grid technology is widely deployed in the United States: 40 percent of the power flowing in the U.S. is managed by our advanced software. We have developed and deployed software managing four of the Nation's seven regional energy markets.

The U.S. electric industry is undergoing a transformation unlike anything we have experienced in the past 100 years. This transformation will create opportunities to enhance the reliability, efficiency, resiliency, and flexibility of the electric system, and strengthen our global competitive advantage.

In my brief remarks today, I would like to highlight the role we play as a technology provider and touch on key trends driving change in the industry. These include an aging grid

infrastructure which must respond to the challenges of a changing energy mix with the growing use of natural gas, renewable energy, and distributed energy resources, including energy storage, as well as the need for increased resiliency to respond to severe weather events.

The first step in developing technology is to listen carefully to our customers, which include America's electric utilities and regional transmission organizations (RTOs) and independent system operators (ISOs). We must thoroughly understand their needs, expectations and challenges.

When it comes to power supply, our customers consistently cite three must-have requirements: reliability, affordability, and sustainability. As we look forward, we also see a clear need for a more flexible and adaptable power system capable of meeting evolving requirements.

A number of technologies, including digital substations, high voltage direct current transmission, power electronics-based equipment, including the Flexible AC Transmission System (FACTS), are being deployed to achieve our customers' core objectives. But to be truly transformational and create an interconnected 21st century grid, public and private partnerships are essential to the continuation of extensive R&D and expansion of pilot projects to test and prove out cutting edge concepts. That's why Senator Cantwell's grid modernization legislation is so important.

However, I want to underscore we can make great strides in modernizing the grid today – and we see this from coast to coast.

We need to begin with the basics, for example upgrading from older analog systems to state-of-the-art digital technology. This will build the foundation for application of the advanced smart grid technology currently in demonstration. We should not wait to begin the upgrades, as this is an incremental process that will take time to implement.

The power industry is facing the difficult challenge of integrating new digital and sustainable technology into an aging, analog-based grid. The technology we provide enables our electric utility and RTO and ISO customers to manage this change, which in turn benefits the end user. By that I mean the new technology will allow energy providers to adopt new services that are mutually beneficial to the utilities and their customers.

There are myriad technical, financial, policy and consumer education issues at play, and it's clear this will be a multi-year undertaking. Deployment and advancement of smart grid technology should be our first priority. It represents a set of critical enabling technology that can reduce the challenges associated with modernizing the grid and optimizing our electricity systems. Smart grids facilitate two-way flows of both information and energy within the system and that's key. Smart grids also allow for greater Volt-VAR control - which improves grid efficiency - and the transfer of instantaneous, real-time data. This gives utility operators greater visibility, operational flexibility and reliability, allowing them to make rapid system responses to changing circumstances on their electric system; on the other side, it gives consumers real time information on their energy usage, allowing them to make informed decisions Smart grids open opportunities for greater customer choice, leading to greater efficiency.

Smart grids are also key to the seamless integration of distributed and renewable energy sources, perhaps the most significant trend we are seeing today. We have seen dramatic growth in distributed and renewable generation sources, which increases the need for integration of two-way power flows to keep the grid stable while incorporating more variable renewable generation, particularly wind and solar.

The DOE has noted that weather related grid disruptions have doubled between 2000 and 2014 highlighting the need for great resiliency. Smart grid and microgrid innovation can improve grid resilience and speed power restoration.

Strong federal leadership and support for grid modernization R&D through public-private partnerships involving utilities, technology suppliers, national labs, and universities is crucial.

We strongly support Senator Cantwell's proposal because it reinforces the strong partnership between the public and private sectors in delivering a more modern grid. In addition, the legislation provides tools for states to conduct analysis of their changing energy mix, performance metrics and distribution planning. We are pleased to support the key objectives of Senator Cantwell's grid modernization bill:

1. Greater visibility and situational awareness;
2. Increased operational flexibility and power flow efficiency; and
3. Improved resiliency, and reliability.

In conclusion, Congress has an important role to play in advancing the modernization of our Nation's electric grid.

The public-private technology collaborations that would be driven by Senator Cantwell's bill will help drive economic growth, strengthen our global competitiveness, and create highly-skilled jobs.

Chairwoman Murkowski, Ranking Member Cantwell, thank you for this opportunity to testify today. I look forward to answering any questions.

The CHAIRMAN. Thank you, Ms. Ericson.
Mr. Dotson, welcome.

STATEMENT OF GREG DOTSON, VICE PRESIDENT FOR ENERGY POLICY, CENTER FOR AMERICAN PROGRESS

Mr. DOTSON. Thank you.

Chairman Murkowski, Senator Cantwell and members of the Committee, my name is Greg Dotson and I'm pleased to testify today on behalf of the Center for American Progress, a nonprofit think tank dedicated to improving the lives of Americans through progressive ideas and actions.

Energy infrastructure forms the backbone of the U.S. economy. We often talk about keeping the lights on but of course, energy also makes possible the most basic of services, drinking water, health care, food production, banking. The importance of energy infrastructure cannot be overstated, and given the high capital cost and long useful life of energy infrastructure the energy policies Congress establishes today will help determine and shape our children and grandchildren's economic and environmental futures. Therefore the Center for American Progress urges the Committee to develop a clean energy policy that responds to today's needs and also anticipates tomorrow's challenges.

As we consider policies to serve us in the coming decades we should be asking some fundamental questions about what we hope to achieve. Will we harness the vast potential of renewable energy sources like wind and solar to power our communities and create jobs? Will we substantially reduce pollution and enjoy a healthier, more sustainable America? Will we build a resilient nation that's ready for the challenges of the future? Will we seize opportunities to empower American families and businesses to take control of their energy use? Any energy bill Congress produces should be judged by how it proposes to answer these questions.

I was pleased to see the comments of Chairman Murkowski last week stating the Committee would strive to produce a bipartisan energy bill that addresses climate change with renewable energy, efficiency and otherwise cutting emissions. A commitment to cutting carbon pollution is the key to a sensible energy policy.

I am providing a lengthier statement for the record, but I'd like to highlight just a few of the bills that are being examined today.

Senator Cantwell's legislation, S. 1243, would take needed steps to modernize the grid by advancing energy storage, developing model grid architectures and conducting demonstration projects for advanced control of the electric distribution system. S. 1243 also amends the Public Utility Regulatory Policies Act or PURPA, to ensure that utilities prepare for a changing climate. According to the Department of Energy's recent Quadrennial Energy Review, extreme weather and climate change is a leading environmental risk to electricity transmission, storage and distribution systems. If you want to know just how important Senator Cantwell's proposal is, just ask the residents of New York and New Jersey who endured Hurricane Sandy and its aftermath. That storm caused power outages for more than 8.5 million customers, and 1.3 million households were without electricity for over a week. All that because the

utility wasn't prepared to withstand a hurricane that many have linked to climate change.

S. 1210, introduced by Senator King, focuses on a key aspect of the future of our electricity grid. Across the country more and more Americans are embracing rooftop solar panels as a way to generate their own electricity, save money and cut pollution. This is creating thousands of new jobs and empowering American households like never before, and the potential is huge.

In 42 of the nation's 50 largest cities a typically sized, solar PV system is now less expensive than power from a utility. The rapid growth of distributed solar power threatens the traditional business model, most investor owned, electric utilities.

In March Joby Warrick of the Washington Post wrote an article entitled, "Utilities wage campaign against rooftop solar." The article details the quote, "determined campaign to stop the home solar insurgency that is rattling the board rooms of the country's government regulated electric monopolies."

In February 2015 the Salt River Project, the large utility in Arizona, approved a $600 per year fee on any customer adding a new rooftop solar system. Before this dramatic step the same utility had actually been financially encouraging its ratepayers to install solar panels. Congress has a role to play in protecting consumer's rights to install solar PV systems without paying exorbitant fees to electric utilities that want to preserve their current business models.

I'd like to urge the Committee to be thoughtful about removing protections for our National Parks and other public lands. It's clear that some in industry will argue that it should be easy to build industrial projects in the National Parks. This is a deeply unpopular idea with the American people, and since these projects are essentially permanent, Congress should not remove protections that the public have come to rely on.

Finally, I was troubled to see the Committee is considering legislation that would allow the Keystone XL pipeline to be subsequently approved even if the State Department denies it in the coming months. That would be a mistake.

Today the Center for American Progress is releasing a new report recommending several improvements to PURPA. I would commend it to you for your review.

And the Center for American Progress would welcome the opportunity to work with the Committee as it continues to consider comprehensive energy legislation.

[The prepared statement of Mr. Dotson follows:]

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Testimony of
Greg Dotson
Vice President for Energy Policy
Center for American Progress

Before the Senate Energy and Natural Resources Committee

May 14, 2015

Chairman Murkowski, Senator Cantwell and members of the committee, my name is Greg Dotson, and I'm pleased to testify today on behalf of the Center for American Progress, a nonprofit think tank dedicated to improving the lives of Americans through progressive ideas and actions.

Today's hearing examines the critically important issue of energy infrastructure. Given the high capital cost and long, useful life of energy infrastructure, the energy policies Congress establishes today will help shape our children and grandchildren's economic and environmental futures.

Therefore the Center for American Progress urges the Committee to develop a clean energy policy that responds to today's needs and anticipates tomorrow's challenges. American innovation is delivering new technology and opportunities to enhance the nation's security and create jobs while reducing pollution.

As we consider policies to serve us in the coming decades, we should be asking some fundamental questions about what we hope to achieve:

- Will we harness the vast potential of renewable energy sources like wind and solar to power our communities and create jobs?
- Will we substantially reduce pollution and enjoy a healthier, more sustainable America?
- Will we build a resilient America that's ready for the challenges of the future?
- Will we seize opportunities to deploy technology that can empower American families and businesses to take control of their energy use?

Any energy bill Congress produces should be judged by how it proposes to answer these questions. An energy bill that is ambitious and science-driven will best meet our climate change challenge and protect the nation for future generations.

More or Less Pollution?

As a threshold matter, a commitment to cutting carbon pollution is the key to a sensible energy policy.

Market forces are currently pushing the United States towards a lower carbon future. While we should expect continued progress, we cannot expect the market alone to sufficiently clean up our energy systems.

Despite substantial progress by the current Administration in addressing climate change, the world is not yet on track to sufficiently cut pollution. According to a recent report from accounting firm PricewaterhouseCoopers, the gap between what the world needs to do and what it is doing has grown for the 6th year in a row. We need to decarbonize the global economy at 6.2% per year, but are only achieving one-seventh of that rate of decarbonization (0.9%).

In the past, some have argued that we cannot afford to cut pollution because doing so might harm our economy. Now, more than ever, the American people see they do not need to choose between clean energy and economic growth. Recent experience in the United States and abroad is demonstrating that we can cut pollution while growing the economy.

Between 2005 and 2014, the U.S. economy (GDP) grew by more than 13 percent while energy-related carbon pollution fell by more than 8 percent. In addition, individual states have adopted carbon cap-and-trade programs and have experienced strong GDP growth in the midst of declining emissions.

Internationally, global carbon emissions from the energy sector remained static in 2014, marking the first time since the International Energy Agency began collecting data that global emissions have stalled or decreased for reasons other than an economic slowdown.

It's increasingly evident that with thoughtful policies we can reduce our carbon pollution while improving the health of our economy. Moreover, achieving significant reductions in carbon pollution will avert the most costly impacts of climate change.

As the Committee considers changes to the nation's energy policies, it's important to remain cognizant of the immense economic impacts of failing to address climate change. The U.S. Council of Economic Advisors warned that while "delaying action can reduce costs in the short run, on net, delaying action to limit the effects of climate change is costly." They estimated that

allowing temperatures to rise by more than 3° Celsius could cost the United States $150 billion every year, in perpetuity, and could cost even more if warming goes beyond 3° Celsius.

Fortunately, there are a number of energy policies that have been demonstrated to cut carbon pollution effectively. States are reducing emissions and growing their economies with cap and trade programs. British Columbia has shown that a carbon tax that recycles its revenue back to businesses and families can be good for both the environment and the economy. State renewable energy standards have helped deploy large amounts of renewable energy generation capacity. These policies demonstrate effective ways to put the country on the course towards a low carbon future. Congress could adopt any of these policies and each would result in significant infrastructure investments.

Legislation before the Committee

Today, the Committee is considering nearly two dozen energy proposals. Five of these proposals would amend the Public Utilities Regulatory Policies Act, or PURPA. Many of these bills constructively point the nation toward cleaner, more resilient energy infrastructure. This policy direction is particularly timely.

The electricity sector in the United States is experiencing a period of dynamic change and is estimated to require $2 trillion of investment over the next 20 years. Technological advancements are making energy available from new and innovative sources and offering an array of new and exciting tools for managing and understanding the way we use energy. Market forces are pushing natural gas in and backing coal out, while renewable energy increases its share of the national market. Regulations, such as the proposed Clean Power Plan, are beginning to chart a course to a low-carbon future. Furthermore, the reality of climate change is barging onto the scene for the electric sector bringing with it challenges such as creating additional strains on the nation's water supplies, which are relied upon for cooling coal-fired and nuclear power plants and turning hydroelectric turbines.

In the recent Quadrennial Energy Review, the Department of Energy stated:

> The U.S. electricity sector is being challenged by a variety of new forces, including a changing generation mix; low load growth; increasing vulnerability to severe weather because of climate change; and growing interactions at the Federal, state, and local levels. Innovative technologies and services are being introduced to the system at an unprecedented rate—often increasing efficiency, improving reliability, and empowering customers, but also injecting uncertainty into electricity-grid operations, traditional regulatory structures, and utility business models. Modernizing the grid will require that these challenges be addressed.

Historically, electric retail markets have been regulated at the state level, but the challenges facing the electricity sector, including a changing climate, powerful market forces, and the need to reduce pollution, are of such importance that the federal government has a strong interest in ensuring they are met. Unfortunately, the state responses to these challenges to date have been uneven. Some state public utility commissions, or PUCs, have been tempted by short-sighted arguments to undermine successful regulatory policies and pretend the challenges of the day do not exist. Others are working overtime to surmount the challenges the nation's faces to create an affordable, reliable clean energy future.

Over the past four decades, Congress has periodically amended PURPA to call upon the state public utility commissions to consider adjusting their electricity policies using an open and evidence-based review process. By simply requiring public utility commissions to examine the merits of various policies through formal proceedings, PURPA has triggered states to adopt smart policies that have helped save energy and promote renewable energy.

The Center for American Progress recommends that Congress embrace this precedent and help set a forward-looking agenda for the nation's public utility commissions to address the important issues facing the electricity sector today. Specifically, Congress should amend PURPA to require state PUCs to consider three policy standards:

- Boost energy-efficiency efforts through technology and regulation.
- Establish policies to encourage utilities to use clean energy to reduce pollution.
- Ensure utilities will have the resilience to function reliably in the future.

Energy efficiency policies can avoid expensive infrastructure investments

The Committee has previously considered energy efficiency proposals at a different hearing, but because efficiency offers an opportunity to avoid needless and expensive infrastructure investments, it is appropriate to mention it here. On a per-kilowatt basis, energy efficiency can reduce energy demand more cheaply and provide superior grid stability than construction of new power plants. According to the American Council for an Energy-Efficient Economy, energy savings from customer energy efficiency programs are typically achieved at 1/3 the cost of new generation resources.

Integration of clean energy and energy storage into the grid

Congress should require PUCs to consider how to encourage integration of clean energy and energy storage into their grid. As the cost of clean-energy technology continues to fall, regulators must be proactive in establishing standards for deployment that achieve economic,

environmental and other societal benefits, and address any institutional biases against generation. Clean-energy sources are nonpolluting, so they do not impose health risks on the communities they serve. They can be placed closer to demand centers, mitigating the need for additional investment in transmission. And with the use of microgrids that can operate independently of the traditional electric grid, clean energy can provide access to electricity during blackouts.

Clear regulatory guidance from state public utility commissioners can send strong signals to energy markets by eliminating barriers for integration of renewable energy, encouraging investment in energy storage to balance loads from intermittent sources of energy, and examining what policies can facilitate the use of fossil-power generation that captures and stores carbon pollution. Regulators that consider the value offered by clean energy beyond their immediate benefits can better serve state consumers with what the DOE calls a "portfolio of electricity options that meet their state specific goals for reliable, affordable, and clean electricity." As inexpensive sources of renewable electricity make up an increasing share of state electricity generation, regulators will also have to adopt better planning and prediction methods to accommodate clean energy in a way that ensures grid stability and reliability. In states that have not already established net metering and interconnection standards, PUCs should consider their application.

S. 1213, introduced by Senator King, focuses on a key aspect of this important and timely issue. Across the country, more and more Americans are embracing rooftop solar panels as a way to generate their own electricity, save on their power bills, and reduce their carbon footprint. Last year was a banner year for the installation of solar photovoltaic, or PV, systems. U.S. power customers installed 30 percent more solar PV capacity in 2014 than they did in the previous year. The Solar Energy Industry Association predicts solar PV installations will grow by another 30 percent in 2015. Falling prices have fueled this tremendous growth in rooftop solar. In 42 of the nation's 50 largest cities, a typically-sized solar PV system is now less expensive than power from the local utility.

The rapid growth of distributed solar power threatens the traditional business model of most investor-owned electric utilities. In March, Joby Warrick of the Washington Post wrote an article entitled "Utilities wage campaign against rooftop solar." The article details the "determined campaign to stop a home-solar insurgency that is rattling the boardrooms of the country's government-regulated electric monopolies."

In February 2015, the Salt River Project in Arizona approved a $600-per-year fee on any customer adding a new rooftop solar system. Arizona Public Service has asked the Arizona Corporation Commission for permission to increase its fees on solar customers to more than $250 per year. In December 2014, Public Service Company of New Mexico proposed charging a fee ranging from $250 per year for small solar PV systems to at least $430 per year for larger home solar PV systems. In Wisconsin, the Public Service Commission voted in November to

allow We Energies to charge customers with solar PV systems about $182 per year. Utilities in other states also have been fighting for new legislation or rate restructuring plans to add fixed fees for solar customers, but not always with success.

The utilities argue that these fixed fees are necessary to ensure solar PV customers pay their fair share to maintain the electricity grid. But that discounts how solar PV supports the grid by reducing peak demand, offsetting the need for new generation capacity, and reducing investment in transmission and distribution infrastructure.

Congress has a role to play in protecting consumers' rights to install solar PV systems without paying exorbitant fees to electric utilities that want to preserve their market share.

S. 1219 would amend PURPA to focus on this issue as well. However, the legislation seems to direct states to focus on the challenges of net metering, rather than the opportunities. It would be a mistake to provide a platform solely for the airing of utility objections to net metering and distributed generation. Distributed generation offers tremendous potential benefits and should be encouraged at the federal and state levels.

Building climate resilience into energy infrastructure

Sen. Cantwell's legislation, S. 1243, would amend PURPA to ensure that utilities prepare for a changing climate. The Department of Energy's *Quadrennial Energy Review*, or QER, makes it clear why S. 1243 is so badly needed.

According to the QER, "extreme weather and climate change is a leading environmental risk" to electricity transmission, storage, and distribution systems. Hurricanes and tropical storms significantly damage electricity infrastructure, as seen in the mass power shutdowns in the New York area after Hurricane Sandy in 2012, resulting in more than 8 million combined customer electricity outages.

S. 1243 would require PUCs to consider how to encourage utility resilience planning to protect investments against extreme weather and drought in a changing climate. Shifting weather patterns will require utilities to invest in resources to harden infrastructure, conserve water, and increase the resilience of their assets. Planning and proactive investment by investor-owned utilities can protect their ratepayers and investors from excessive recovery costs and falling operational efficiencies due to climate change. Regulators could encourage their utilities to develop long-term plans for their facilities that determine acceptable levels of risk to climate change, particularly during rate cases to evaluate investments in new assets. Such planning will support grid reliability and long-term affordability.

The Center for American Progress would welcome the opportunity to work with the committee as it continues to consider comprehensive energy legislation.

The CHAIRMAN. Thank you, Mr. Dotson.
Mr. Hunter, welcome.

STATEMENT OF JAMES L. HUNTER, UTILITY DEPARTMENT DIRECTOR, INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

Mr. HUNTER. Thank you.

Good morning, Ms. Chairman, members of the Committee, Ranking Member. My name is Jim Hunter. I'm the Director of the International Brotherhood of Electrical Workers Utility Department. I've been asked by our President Ed Hill to speak today on behalf of the IBEW, and I want to thank you for inviting us.

The IBEW represents about 720,000 members in the U.S. and Canada. 220,000 of those are in the utility business. That's electric, gas and water.

I personally have worked in the industry now for over 42 years. The energy sector is facing a large number of retirements over the next few years. According to industry experts at the Center for Energy Workforce Development, the average worker is about 53 years old. Over the next ten years 55 percent of those will be needed to be replaced. They'll be retirement age.

My point in talking about the large number of people leaving the industry is to talk about how we replace and train those employees. The joint apprenticeship model works. Earn while you learn.

The IBEW in conjunction with several of our utility partners have formed the National Utility Industry Training Fund, NUITF. We're a nonprofit, 501(c)3. Our model provides a standardized curriculum of certifications that are nationally recognized.

We're using the construction model from the National Joint Apprenticeship Training Committee for alignment and substation mechanic curriculum, and we have utilized a boot camp technology to filter possible new hires coming into the companies. Our programs are DOL-certified, and combine classroom training with sophisticated, online simulations and workbooks. New employees learn from a seasoned veteran while earning a living wage and benefits.

You know, many people are not cut out for college and want to start working right out of high school or when they get out of the military. Jobs in the electric and gas sectors provide a good, secure and decent wage and benefits. The push for community colleges is great, but there needs to be some emphasis placed on programs such as ours as an alternative.

President Hill has always said many times that kids need to be taught how to work. We understand that being taught by an experienced craftsman is by far a better way to convey those skills. Joint apprenticeships work and they work well.

The idea of working while learning a trade from a master craftsman dates back to ancient times. Many inner city kids don't have the funding to go to community college or even our boot camps, so financial aid is an important factor here.

We've been working with Senator Cantwell on a training bill that we believe her bill, S. 1304, recognizes joint apprenticeships programs and their importance. And we appreciate that.

Just a moment to talk about comprehensive legislation that you all are looking at.

The IBEW firmly believes that comprehensive legislation is needed. Our markets are broken. Our base load plants, especially coal and nuclear, are in jeopardy of closing in many cases. The reliability of the grid will depend on Congress fixing the markets. We must incorporate renewables and energy efficiencies into the grid in an organized and fair manner. The utility must supply the needed generation 24/7, including variable sources. The reliability customers have come to expect comes at a cost. And we cannot rely on a patchwork of rules to provide the level of reliability we've come to expect.

I've included a slide from a recent EPRI report. The slide is of a net zero home in California. The important thing to take away from the slide is the line at the top. That's the level of generation that must be ready at all times to ensure a safe, reliable system, and the question is who pays for that reliability?

I'd also like to comment on transmission siting. Backstop siting authority is essential to ensure a reliable grid to use renewables efficiently. Siting of transmission is the most difficult part of any transmission project, and it becomes a local, political quagmire if there's not some type of federal backstop authority.

Thank you.

[The prepared statement of Mr. Hunter follows:]

James L. Hunter
Utility Director
International Brotherhood of Electrical Workers (IBEW)

Testimony of James L. Hunter
Director, International Brotherhood of Electrical Workers Utility Department
Before the
Energy and Natural Resource Committee
United States Senate
Washington, DC
May 14th 2015

"Joint Apprenticeship Programs, Earn while you learn"

Good morning Ms. Chairwoman and Members of the Committee:

My name is James Hunter and I am the Director of the International Brotherhood of Electrical Workers (IBEW) Utility Department. I have been asked by our President, Ed Hill to speak to you today on behalf of the IBEW. Thank you for inviting us to comment this morning.

The IBEW represents 720,000 members more than 220,000 of them are utility workers. We represent Electrical as well as Gas members across the U.S. and Canada.

I personally have worked in the Energy sector for over 42 years.

Situation

The Energy sector is facing a large number of retirements over the next few years. According to the industry experts at the Center for Energy Workforce Development "CEWD" the average age for workers is 53 years old. Over the next 10 years 55% of the industry will need to be replaced.

My point in talking about the large number of people leaving the industry is to talk about how we replace and train those new employees. The joint apprenticeship model works. The IBEW in conjunction with several of our industry partners have formed the National Utility Industry Training Fund "NUITF". NUITF is a non-profit 501-C3. Our model provides a standardized curriculum and certifications that are nationally recognized. We are using the construction model from the National Joint Apprentice Training Committee for Lineman and Sub-Station mechanic's curriculum and have utilized a boot camp logic to filter possible new hires into the companies. Our programs are DOL certified and combine classroom training with sophisticated online simulations and workbooks. The new employee learns from the seasoned veteran while earning a living wage with benefits. The boot camps are between 6 and 12 weeks and provide the individual with the opportunity to see what the job really entails. The lineman boot camp exposes people to climbing poles as well as operating a bucket truck and learning the tools of the trade. They are given intense classroom courses and are evaluated by the companies as they go through the classes. We are working with other employers to come up with a gas program.

Many people are not cut out for college and want to start working right out of school or the military. Jobs in the electric and gas sectors provide a good secure job with decent wages and benefits. The push for community college is great but there needs to be some emphasis placed on

programs such as ours as an alternative. Our 6 week class runs about $6000 per person. We have received grants in Michigan and Kansas to run some boot camps and we have partnered with the local WIB's to help with basic training needed for an applicant. DTE has hired over 48 people that have successfully completed the program. The latest boot camp had almost 50% veterans in it. In some cases the utility hired the person first and then paid them as they went through the boot camp. We believe there should be funding made available for people who are interested in the utility field and want to take a real life course such as the boot camps. NUITF has a database of people who have gone through the boot camps and we partner them up with utilities and construction companies that are hiring.

Suggested Solutions

IBEW President Ed Hill as said many times that kids need to be taught how to work. We understand that being taught by experienced craftsman is by far the best way to convey skills. Joint apprenticeships work and work well. The idea of working while learning a trade from a master craftsman dates back to ancient times. The NUITF boot camp model exposes people to the requirements of the job and what will be expected of them once they are hired. It provides the company with a person who is ready to go to work day one with basic knowledge of the job and the equipment. Many intercity kids don't have the funding to go to community colleges or even our boot camps. Finical aid is important.

Comments on Comprehensive Energy Legislation

The IBEW firmly believes comprehensive legislation is needed. Our markets are broken and our base load plants, both coal and nuclear are in jeopardy of closing. The reliability of the grid will depend on Congress fixing the markets. We must incorporate renewables and energy efficiency into the grid in an organized and fair manner. The utility must supply the needed generation 24/7 including variable sources. The reliability customers expect comes at a cost and we cannot rely on a patchwork of rules to provide the level of reliability we have come to expect. I have included a slide (Fig. 3.) from a recent EPRI report. The slide shows a net-zero home. The important thing to take away from the slide is the line at the top. That level of generation must be ready to insure a safe reliable system and the question becomes who will pay for it.

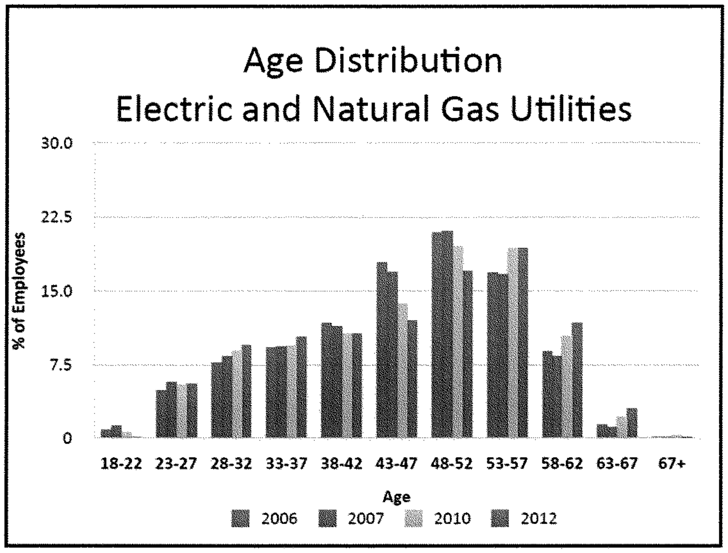


Fig. 1. Age Distribution in Electric and Natural Gas Utilities, *Gaps in the Energy Workforce Pipeline 2013 Survey Results*, (Center for Workforce Development)

	Potential Replacements 2013 - 2017		Potential Replacements 2018 - 2022	
Job Category	**Potential Attrition & Retirement**	**Estimated Number of Replacements**	**Potential Retirement**	**Estimated Number of Replacements**
Lineworkers	32%	24,100	14%	10,300
Technicians	41%	28,300	14%	10,100
Plant Operators	42%	14,900	13%	4,600
Engineers	34%	9,200	12%	2,900
Total	**36%**	**76,500**	**14%**	**27,900**

Totals exclude Nuclear

Fig. 2. Potential Replacements, *Gaps in the Energy Workforce Pipeline 2013 Survey Results*, (Center for Workforce Development)

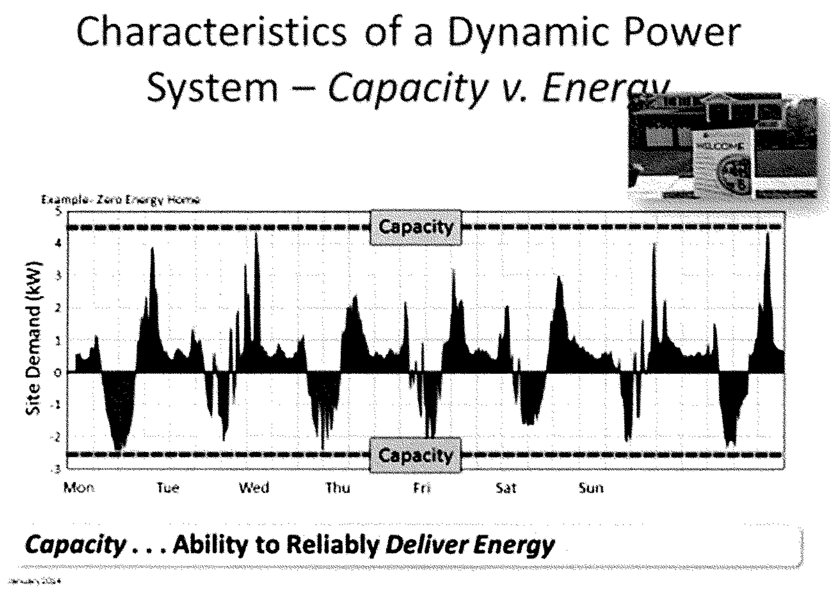


Fig. 3. Example of a Zero Energy Home, *Characteristics of a Dynamic Power System,* (ERPI)

The CHAIRMAN. Thank you, Mr. Hunter.
Dr. Kalk, welcome to the Committee.

STATEMENT OF DR. BRIAN P. KALK, COMMISSIONER, NORTH DAKOTA PUBLIC SERVICE COMMISSION

Dr. KALK. Thank you, Madam Chair, Ranking Member Cantwell and Committee members. I really appreciate this opportunity. My name is Brian Kalk, Commissioner for North Dakota and my wife told me to make sure I say hello to Senator Hoeven. So, good to see you again, Senator.

I hold the portfolios for electric generation in transmission, pipeline safety and rate regulation. I also chair the Clean Coal Subcommittee for NARUC.

Over the past three years the North Dakota PSC has sited over $4 billion of energy resources including jurisdiction electric and liquid transmission lines, wind farms, natural gas processing plants and peaking facilities. These energy resources coupled with our fleet of coal and hydroelectric power make North Dakota an all of the above energy producer. We've approved updates to our fleet of coal generation ensuring they're in compliance with existing federal laws.

The North Dakota PSC supports all energy markets but strongly believes the final determination of a state's energy portfolio mix and resulting impact on rates should be left to each state's regulator and not be affected by neighboring states or federal policies.

All types of energy production are becoming more efficient. Capacity factors for wind are over 50 percent. Natural gas plants are ever improving. Solar shows promise, but we must always remember that base load power is always going to be critical.

I also urge your support for expanding CO2 utilization research funding to continue the development of technologies that advance the use of coal. The Kemper County Energy Facility shows promise. It uses lignite coal, a strategic resource, captures the CO2 for enhanced oil recovery, produces ammonia and sulfuric acid and provides 582 megawatts of base load power.

North Dakota has experienced unprecedented expansion in the amount of transmission siting applications. Our existing process continues to work smoothly, but even with North Dakota's diligence in processing applications hurdles beyond the state's control can occur to slow the siting process.

When a Federal nexus exists triggering the implementation of NEPA, analysis can take extended periods of time. It would be imprudent to render a final decision without a complete NEPA analysis. Legislation should not be implemented that would penalize states for expanded timeframe of approval when it is the federal agencies that are the actual delay.

We would strongly object to any efforts to move the siting of jurisdiction electric transmission lines to the Federal level; however, we would support any efforts to decrease the timeframe of Federal agency's review on multijurisdictional projects.

North Dakota, as we know, is located next to Canada. We have also experienced delays in Federal approval on pipeline border crossings, and fully support efforts to streamline and expedite energy infrastructure projects between the U.S. and Canada.

I believe the states, not the Federal Government, ought to have jurisdiction over the retail rates and services. The states have been and will be the laboratories for innovation for retail electric supply. Some innovations work well in one state, but perhaps not in others depending on each unique circumstance.

While PURPA attempts to address this situation there have been situations where federal regulators have attempted to use PURPA to undermine state jurisdiction.

The development of the power grid should be done by professionals and remain consistent with least cost planning and need. It's important to ensure that North Dakota and the rest of our states have the necessary power to provide and maintain base load power and have sufficient ancillary services to ensure continued operation of our electric system. While North Dakota utilizes a full range of energy resources, concern exists with integrating renewables ensuring the system wide reliability is maintained.

The need for power must always be the key consideration. There is construction. The construction of QFs by companies does not take into account if there is an actual need for the power in the state. The continuation of the mandatory purchase obligation as it exists today can impose significant, unnecessary costs to consumers.

In summary, North Dakota appreciates continued Federal effort to expedite products that are multijurisdictional. North Dakota supports and practices an all of the above energy policy. Lowest cost and need are the bedrock principle of public utility ratemaking. There definitely is a place for renewables in the power grid but we must not forget about base load power.

Finally, as a retired Marine and veteran of Desert Storm in Iraq, I'd like to thank the Committee for your work on increasing the energy security of our country. I truly believe that energy security for the United States not only enhances our foreign policy options but will result in less impact to rate payers and a more reliable power grid.

Thank you, Madam Chair, for the opportunity. I'd be happy to answer any questions.

[The prepared statement of Dr. Kalk follows:]

Testimony of Brian P. Kalk, Ph.D.
North Dakota Public Service Commissioner
Before the U.S. Senate Energy and Natural Resources Committee
Hearing on Energy Infrastructure Legislation
May 14, 2015

Madam Chair, Ranking Member Cantwell, and Committee Members, thank you for the opportunity to testify before you today. My name is Brian Kalk, Commissioner for the North Dakota Public Service Commission (NDPSC). I hold the portfolios for Electricity Generation and Transmission, Pipeline Safety, and Electricity Rate Regulation for North Dakota. I also Chair the Clean Coal Subcommittee for the National Association of Regulatory Utility Commissioners and serve as North Dakota's representative on the Regional Transmission Organizations we operate in.

Over the past three years, the NDPSC has sited over four billion dollars of energy resources, including jurisdictional electric and liquid transmission lines, wind farms, natural gas processing plants and peaking facilities. These expanded energy resources, coupled with our existing generation fleet of coal and hydroelectric power, truly make North Dakota an "all of the above" energy producer. We have also approved numerous updates to our fleet of coal generation to ensure they are in compliance with existing federal laws.

The NDPSC supports all energy markets, but strongly believes the final determination of a state's energy portfolio mix and resulting impact on rates should be left to each state's regulator and not be affected by neighboring states or federal policies.

Let me explain. With a state like North Dakota that truly practices an "all of the above" energy strategy, and holds to the principles of rate regulation (lowest cost and need), certainty is provided to customers regarding rates and stability of the power grid. In contrast, some states have chosen to mandate certain types of electric generation while ignoring lowest cost and need. I understand and respect the rights of these states to make those types of decisions, but I would stress that neighboring states should not bear the burden of higher costs of electricity.

States have different resources and local policy considerations. This reinforces the need for states to be able to determine their own energy mix and need. As this Committee debates the future of energy policy, I urge the Committee to always be mindful of the impact of cost and reliability.

My experience in North Dakota is that all types of energy production are becoming more efficient. Capacity factors for wind are over 50 percent, combined cycle and peaking natural gas plants are ever improving, solar shows promise in some regions, but we must always be mindful of "need and cost" as we grow our generation fleet and the fact that "base load" power will always be critical to the power grid.

Finally, I urge your support for expanding CO2 utilization research funding to continue development of technologies that preserve and advance the use of coal in our nation. Facilities like the Kemper County Energy Facility show great promise for the future of coal. This facility

uses lignite coal—a strategic resource—captures the CO2 for enhanced oil recovery, produces ammonia and sulfuric acid and perhaps most importantly, provides 582 mega-watts of much needed "base load" power to the regional utility and their customers.

My remaining time will cover two key areas of energy infrastructure: transmission development and potential changes to the Public Utilities Regulatory Policies Act (PURPA).

1. Transmission Development (Electric & Pipelines)

North Dakota has experienced unprecedented expansion in the amount of transmission siting applications brought before the NDPSC. Our existing processes and statutory framework continue to work smoothly to facilitate growth while maintaining oversight in this area.

Even with North Dakota's diligence in processing applications, hurdles beyond the state's control can occur to slow the siting process. An example would be when a "federal nexus" exists triggering implementation of the National Environmental Policy Act (NEPA) for the company building the transmission line. Such analysis can take extended periods of time. It would be imprudent of state regulators to render a final siting decision without the consideration of a complete NEPA analysis. Thus, it is important to consider the various components to transmission planning and siting. Legislation should not be implemented that could force states to render decisions before all necessary information is available or penalize states for expanded time frame of final approval when it is the federal agencies that are the actual delay.

The NDPSC has also experienced the situation where a transmission pipeline has received the final approval in North Dakota but has become significantly delayed in neighboring states. Since we are located next to Canada, we have also experienced delays in federal approval on pipeline border crossings and fully support efforts to streamline and expedite energy infrastructure projects between the United States and Canada.

North Dakota supports existing procedures for granting interconnection to the power grid utilized by the Regional Transmission Organizations operating in our state. In addition, we have in state law the "Right of First Refusal" on electric transmission construction.

2. PURPA Updates and Qualifying Facilities (QF)

Generally speaking, I believe that the states, not the federal government, ought to have jurisdiction over retail rates and services. The states have been and will be the laboratories of innovation for retail electricity supply. Some of the innovations work well for the consumers in one state and do not meet expectations in others depending upon the unique circumstances that exist in each state. While PURPA attempts to address this situation, there have been situations where federal regulators have attempted to use PURPA to undermine traditional state jurisdiction. Additionally, specifically in those states with limited Commission staff and resources, a multitude of PURPA proceedings initiated due to Congressional legislation (as was the case after EPAct 05) creates staffing and resource shortages with regard to the other duties for which a state utility commission is responsible. This can result in delays in the siting and permitting energy infrastructure improvements.

The NDPSC welcomes the opportunity to exercise our traditional regulatory authority and any new or clarifying authority which allows us to assess our needs and help prescribe ways to ensure secure, reliable and affordable electricity to the people of North Dakota. Therefore, we strongly support individual states' rights to incentivize energy development and infrastructure. However, a state should not be required to subsidize one particular industry or technology over another. The development of the power grid should be done by professionals and remain consistent with traditional least cost planning.

It is important to be able to ensure that North Dakota has the necessary power to provide and maintain base load power and to have sufficient ancillary services to ensure continual operation of our electrical system. By baseload, I mean large-output electric generation facilities that contribute to reliability, not intermittent power or that affected by weather or climate conditions.

While North Dakota utilizes a full range of energy resources, concern exists with integrating renewables and ensuring that system-wide reliability is maintained. North Dakota understands the grid is evolving, but costs are still a vital consideration.

The need for power must always be a key consideration. The construction of QF by companies does not necessarily take into account if there is an actual need for the power in the state. The continuation of the mandatory purchase obligation, as it exists today, can impose significant and unnecessary costs on consumers.

As you know, PURPA requires regulated utilities to buy energy from qualifying renewable generation projects at rates established by state commissions. In North Dakota, we establish them annually as part of our utilities' tariffs. Tariff rates for energy are around 3 cents a kWh, with capacity payments varying depending on the length of the contract. We do not have any significant QFs operating in North Dakota because our energy prices are very low in terms of market energy as well as self-generation.

The North Dakota Legislature recently rejected legislation to create feed-in-tariffs. North Dakota recognizes and supports the ability of each state to determine what is best for its customers and strongly believes this planning should remain at the state level.

North Dakota values establishing and maintaining strong working relationships at all jurisdictional levels including local, state, and federal. North Dakota understands the federal government plays an important role in energy development, and is generally supportive of this role as long as it does not usurp state authority.

Conclusion

Summarize key points.

- North Dakota appreciates continued federal efforts to expedite projects that are multi-jurisdictional.
- North Dakota supports, and practices, an "all of the above" energy policy.
- Cost and need are the bedrock principles of public utility rate making.

- There is a place for renewable energy in the power grid, but we MUST NOT forget about the need for base load power.
- As a retired U.S. Marine, I would like to thank this Committee for their work on increasing the energy security of our country. I truly believe that energy security for the United States not only enhances our foreign policy options, but will result in less impact to ratepayers and a more reliable power grid.

Madam Chair, this concludes my written testimony. I would gladly stand for any questions at this time.

The CHAIRMAN. Thank you, Dr. Kalk. I appreciate the testimony of each of you here this morning. We have lots to talk about. Let me start with you, Dr. Kalk.

You have noted that one area that is a little bit problematic here in constructing the transmission infrastructure is this disconnect between the Federal NEPA process and the state regulatory process. As I mentioned in my opening, a lot of what you see with the measures that we will be considering put requirements on our state and our state regulators. That can end up being some of the problem here.

Can you give some examples of where and how the Federal NEPA process has delayed the state process and ultimately then the project? More importantly, what can we do to address that? As a state regulator what would you suggest that we do to address it?

Dr. KALK. Thank you, Madam Chair, for the question.

A specific example I would talk about is North Dakota needs more electricity right now. And Basin Electric, one of our rural coops, put an application in for a 250 mile, 345 kV line in the central part of the state to the Northwest.

The Public Service Commission went out and we held three different hearings along the route. We worked with our state to make sure that it met with the Fish and Wildlife goals, our North Dakota game and fish goals, and our state historical society. But because it was a co-op there was a Federal nexus created because they get our U.S. dollars.

And so North Dakota, we completed our siting hearings. We had North Dakota agencies on board, but the final NEPA review was not completed and that NEPA review took an extra six to eight months until we finally got the NEPA approval.

And the state, we put the order out there saying we approve it contingent upon final record of no impact, if you will. But I would say that these agencies, it seems in conversation with them, they have the data. All they have to do is to make a decision. So once they've collected the data, anything that this body can do to get them to analyze and make the decision. In North Dakota we make decisions. You get the data in front of you, you make the decisions. My frustration with the Federal agencies is they have the data, but they refuse to pull the trigger and make the decision and then move the process forward.

When I was in——

The CHAIRMAN. So maybe some timelines might be helpful?

Dr. KALK. Yes, Ma'am.

When I was the Environmental Compliance Officer at Camp Pendleton everything we did had a Federal nexus. We would still remain close to the timeline. We'd follow the process and make decisions.

The CHAIRMAN. Thank you. I appreciate that.

Ms. Bowman, I wanted to ask you about siting issues because that has been raised by several this morning and siting on our public lands. Under the current statutory framework for siting natural gas pipelines across our National Park Service lands can you give me, I do not know if there is a typical time frame? Some kind of an understanding in terms of the timing that it takes to approve a right-of-way for a pipeline project going through National Park

Service lands, and then what this does in terms of impacting the project itself? Because what we are doing is we are creating delays here, but I do not have a sense as to what kind of a time frame we are actually talking about.

Ms. BOWMAN. Alright. So one of the largest issues with respect to siting a pipeline through National Park lands is that the project developer needs to go to Congress so that they get the statutory authority to the Secretary of the Department of the Interior. And different projects across the country, I believe one in Alaska where it was sited in Denali.

The CHAIRMAN. We have got the corridor sited, yes.

Ms. BOWMAN. Yeah, that took four years for that authority to be given. And only then can you start the real permitting process at the end——

The CHAIRMAN. Was Alaska's example what we see in the lower 48 as well on our Park Service lands?

Ms. BOWMAN. There's another example in New York City where it's a three mile pipeline, and it took one and a half years to get that authority. So you're waiting 1½ to 4 years to get——

The CHAIRMAN. And that is just to get the permit. That is nothing more than just the authority.

Ms. BOWMAN. That's not even the permit. That's to give the authority to the Department of Interior Secretary so that then they can go through the process to get the permit.

So then they waited, at least in New York project, another 19 months before the permit was given, and now it's finally under construction.

The CHAIRMAN. Thank you.

Mr. Weisgall, I appreciated your comments about the bill that I have introduced, S. 1217, on the transmission and siting. I know we think it is going to be important to allow FERC to operate in this ombudsman type role, if you will, when it comes to agency coordination and to address problems that may be presenting in the process. The question that I have for you is related to corridors. The national interest electric transmission corridor designations and the transmission siting process that was called for in EPACT '05, those have been overturned. Are corridor designations still relevant today? How big of a deal is that?

Mr. WEISGALL. The process really hasn't worked, so I think they are less relevant then to some extent. I mean, what we're proposing here, and in response a little bit to Commissioner Kalk from North Dakota, we're not proposing here a greater Federal role. The idea here is an improved Federal role.

You know, a lot of the transmission issues we're looking at do not involve national parks, but there's still at least BLM, Fish and Wildlife and Forest Service. So you've got three different Federal agencies there.

So it's really, you know, we had this rapid response team that was designed to expedite the process. It was certainly the right idea. I mean, you need coordination.

There is as many as nine or ten Federal agencies at any time on transmission. This is, of course, largely a western issue where's there's much more Federal land. So we've been frustrated.

We've got one segment of our energy gateway project, Gateway West, we're now ten years and waiting. And part of the problem there is we'll go through a review with, let's say, BLM, but then there will be a new regulation. And nothing is grandfathered as such. So you, kind of, start over again. That's what we're doing.

I don't have draft language there, but think about that grandfathering point. That if you're going through a lengthy transmission approval process with one of the Federal Government agencies. You get that approval, and then you've got to change through a new policy, a new manual, something new, at the agency.

Something needs to be grandfathered because otherwise you're just playing this over and over again, and it's Groundhog Day. I mean, you've just got to start over from the beginning.

So that's some of the challenges that we face. And ten years is, I mean, it's really hard to work with those kinds of timeframes.

The CHAIRMAN. I would think it is not doable most of the time. I appreciate that perspective. Thank you.

Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair.

I would actually like to continue with Mr. Weisgall because the Quadrennial Energy Review that we had a hearing on a few weeks ago with the Secretary was all about infrastructure improvements. Rail infrastructure has close to a 4000 percent increase in transporting crude by rail. This is a big issue in the Pacific Northwest.

I also noted that roughly 40 percent of what is moved by rail is coal; in fact, 68 percent of coal used for generating electricity is delivered to the power plants by rail. Is it not the case you have three utilities who are substantial coal generators? And Berkshire Hathaway also owns BNSF, the largest rail carrier of powder-basin coal?

So isn't it the case that getting rid of this PURPA requirement would greatly benefit your company financially and your profit margin by reducing competition for central station generation?

Mr. WEISGALL. I would say the answer is an unqualified no, Senator. Let me try to explain.

What we're trying, our legislative proposal by including an energy imbalanced market as a comparable market is actually designed to enhance the role of renewables. This market structure that we have entered into with the California ISOs has been endorsed by Natural Resources Defense Council, the American Wind Energy Association, Solar Energy Industries Association. They see a greater role for renewables with an enhanced geographic footprint to get rid of some of the balkanization that exists today in the West. Our view would be that by including this energy imbalanced market in PURPA you will have more entrants into that energy imbalanced market. That's going to be good for renewables. So if we can get more renewables on the grid, fewer greenhouse gas emission reductions and lower cost to customers, that's a trifecta.

Yes, our company does have coal resources. We're at 35 percent overall today. We anticipate going down to 26 percent coal.

Senator CANTWELL. So you—I just want——

Mr. WEISGALL. But for renewables we think that this is a big plus for renewables, just not for high cost renewables.

Senator CANTWELL. You think changing the PURPA requirement—that was about diversifying energy sources so that people could get renewables—so you think retracting that language is good for renewables?

Mr. WEISGALL. It doesn't retract the language. It simply includes a new, comparable market provision which Congress itself put in. In 2005 Congress spelled out two areas where there would be the mandatory purchase obligation would be removed and a third area called comparable markets. We're coming in with an example of that comparable market. All you need to do is look at the interest groups that support this energy imbalanced market that sees how a larger footprint is good for renewables.

Senator CANTWELL. Well, I can tell you one big group of people that does not support such a change and it is the Pacific Northwest. The Pacific Northwest is not going to support another cooked up scheme from California ISOs about energy markets. Okay? We are not getting screwed over again by another ENRON style scheme, like: "look over here, but don't pay attention to what is really going on over here."

I see you making money on the repeal of this PURPA language. To me, it is bothersome to say nothing of oil trains and your slow response in removing old oil trains. Now you are coming here and trying to undo a very important law.

I hope we can get some information from you about exactly how you think that that is not going to disadvantage the people moving forward. I would love to get Berkshire Hathaway on the record, supporting a more aggressive removal of the DOT–111 and CPC–1232 trains which you own and commiting to better pricing for agricultural products that are getting pushed off the rails because of all of these energy resources. All of these are big questions right in your wheelhouse, and I hope that you can help us get some resolution to them. I say that because I see you are the Vice President for Legislative and Regulatory Affairs, and these issues, as they relate to the Quadrennial Energy Review, are exactly what the Secretary of Energy says we need to deal with as far as energy infrastructure.

Mr. WEISGALL. Two very quick points.

Number one, I appreciate the reference to Berkshire Hathaway Energy, to Berkshire Hathaway. We are with Berkshire Hathaway Energy. I really can't speak for Burlington Northern.

Second point, I would like to work with you on these issues because we've seen already in the first five months of this energy imbalance market tremendous cost savings for customers. So going to your point about enhanced profits, we're customer centric. If we see cost savings that's good, but I appreciate your comments and would like to follow up with you.

Senator CANTWELL. I am sure that is exactly how ENRON sold their plan to the Californians, and why they should have created that market as well. We all know how that story ended.

Thank you, Madam Chair.

Mr. WEISGALL. Well, there are, you know, a number of entrants in energy imbalance marketing including Puget Sound Energy and other utilities are looking, so it's an evolving issue. And an evolving market. So far it's worked very well for our customers.

The CHAIRMAN. Let us go to Senator Capito.

Senator CAPITO. Thank you, Madam Chair.

I want to thank the members of the panel for being with us here today. It is, obviously, a very important issue. There are lots of bills out there.

I want to start with Ms. Bowman. I would like to thank ANGA for supporting S. 1210, which is my bill, the permitting reform bill, that I introduced with Senators Cassidy and Heitkamp last week.

I have heard a repeating theme, maybe not everybody on the panel has mentioned this, but the stalling out or the length of time of the permitting creating so much uncertainty at a time when we have a critical need for new and improved and expanded infrastructure.

Dr. Kalk, you said in your statement, I think in response to a question, "the agencies have the data, they just need to make the decision."

That is what my bill really is about. It is about creating timelines. It is not about running roughshod over any kind of environmental review or anything. It is just trying to move the process along to keep it from stalling out.

Ms. Bowman, I would like to ask specifically how do you think that would help and what kind of results could we see by having specific timelines to meet the permitting process?

Ms. BOWMAN. Thank you, Senator, and thank you very much for your bill.

One of the biggest things that we see as an improvement from what your bill lays out is obviously, streamlining the permitting process, but allowing for or pushing toward a concurrent review.

Senator CAPITO. Right, that is in the bill.

Ms. BOWMAN. Among the agencies. That's something that is very important because it really helps move the decision process along.

But also the other point here is that you kind of create, establish an early detector system for issues. And that really enables us, especially in this environment where there's a lot of activism at the state and local level, if we get issued identified early and start working on resolutions around those issues with the agencies that will greatly improve our timelines.

So, thank you for the bill, and we look forward to hoping that gets into law.

Senator CAPITO. Thank you, thank you very much.

Mr. Hunter, I wanted to ask you a question as well. You were mentioning a lot about the workforce of tomorrow, and certainly we have seen in West Virginia and Pennsylvania a massive increase in natural gas production. One of the issues has been the workforce.

Obviously it comes in a part of West Virginia that we had had massive population decline because the steel industry had declined and our workforce had declined. It irks, I think, a lot of West Virginians when they are driving through Marshall County and they see all of the Texas and Oklahoma license plates because we want to see this development occur.

You mentioned ways to increase that workforce. How do you see that developing in that particular region across the country, and is it any different anywhere else?

Mr. HUNTER. Well I appreciate the question. I can tell you most of those plates are also non-union, so we don't like them being there either. [Laughter.]

But what we're seeing is we've got a massive amount of retirements in the energy industry.

Senator CAPITO. Right.

Mr. HUNTER. Especially in gas and utilities. So all we have been trying to say is that the idea of a joint apprenticeship program where somebody is coming right out of school, getting a job, working. The utilities, you know, we've worked closely with AEP and others. I mean, we are definitely hiring. The utility industry is hiring. And they're jobs where you stay home. You're not traveling thousands of miles away. So we think that just this, trying to keep the utilities profitable. They are in the hiring mode. We think is a good opportunity for a lot of people.

We just had Detroit as a for instance. We had a large granite DTE. They turned around they hired 48 people, a lot of them were long term unemployed that we got from the Workforce Investment Boards that had been unemployed for over 18 months. Our last group, half of them were retired or veterans.

Senator CAPITO. Thank you.

Do you have concerns with the President's Clean Power Plan? Obviously that is going to influence. It is a different topic, but it definitely is something in my state with the metrics there who are very concerned about our power generation abilities. Have you all weighed in on that?

Mr. HUNTER. Yes, we have, and you know, we're already closing 60,000 megawatts because of MAFs. And now to turn around and take the possibility of another 50,000 megawatts of coal being retired, we're concerned about reliability as well as jobs. We don't think it's a good idea at all.

Senator CAPITO. Alright, thank you very much.

The CHAIRMAN. Thank you, Senator Capito.

Senator Franken.

Senator FRANKEN. Thank you, Madam Chair.

The Department of Energy recently released the first installment of the Quadrennial Energy Review. According to that report weather was responsible for half of the reported grid outages between 2011 and '14, and those outages resulted in the vast majority of customer interruption hours. In the future electric utility customers will likely see even more frequent and longer duration outages as a result of extreme weather events which are becoming more severe because of climate change.

So now more than ever it is essential that we minimize the impact of weather-related grid outages to American households and businesses. That is why I joined Ranking Member Cantwell and other members of the Committee in support of the Grid Modernization Act which will help make the grid more flexible, efficient and resilient. For anyone. What can utilities and regulators do now to reduce the likelihood of weather-related outages and to ensure that customers get their power back on as quickly as possible during such an event?

Mr. DOTSON. Senator, I'd love to answer that question. I think it's going to depend on the various state and various utility. When

you look back at Hurricane Sandy, I think a lot of people ask questions. Did it make sense to have substations that were below the 50 level, 50 year flood plain in the city and that turned out to be a mistake? And I think New York is doing a lot to try and address that so they do have a system that's more resilient.

In other parts of the country, you know, in the south you have a situation where water, it's getting so hot during some parts of the year that it can no longer be used to cool thermal power plants. That's a very serious issue, and steps can be taken there to diversify generation or to install different cooling systems to address it. So I think it's a question that going to be a site specific, but it's one that I support the legislation because I think it's important to be asking those questions today.

Mr. WEISGALL. Quick answer.

Senator FRANKEN. Sure.

Mr. WEISGALL. It's a very good question. Our three utilities are members of what's called the Spare Transformer Equipment Program which is called STEP. Edison Electric Institute CEIs and CEOs are very aware of this issue, and they've actually put together a list of action items concerning more engagement with government partners to deal with these potential outages. They can be regional events. They could even be longer. But more engagement with the Federal Government, better coordination with railroads, just in terms of having to move transformers if there's these kinds of even more serious issues, even getting into DOD air lift capability. So there could well be a role there for Congress to have an overlay to assist in this area, but certainly it is an important one.

Ms. ERICSON. I think that there are suites of technologies out there that are being demonstrated right now by the utilities, granted on a, or by the ISOs and the utilities, on a regional basis because each region has its own needs and challenges. It's happening at both the transmission and the distribution level, different sets of technologies.

Senator FRANKEN. I want to talk about distributed energy, but continue.

Ms. ERICSON. At the transmission level which is the big grid level, the focus has been how can we take all of this wonderful big data that is available and the data analytics that are available now and use that information to get instantaneous readings and therefore actually be able to prevent blackouts and certainly keep them from cascading?

And then on the reverse side there's been a lot of automation that has gone into the system that helps to automate part of the restoration process, and the lines people, the dispatch crews that are out there, are all equipped digitally now. They have a lot of remote information, a lot of telecommunications, IT information, that is speeding up the restoration process.

On the distribution level there are a couple of things. We need a lot of work here, and obviously a lot more is happening at the distribution level. The part of the reason that we're seeing the trend towards microgrids, obviously, is because people want to be self-generating. They want to be self-managing. They want to be self-storing, and they want to be able to disconnect to protect themselves. And that technology, again, in demonstration in many

places needs to be integrated into the bigger transmission level. We have bulk resources, distributed energy resources. We have microgrids. We have energy storage. And for the sake of efficiency, for the sake of optimizing power flow and for the sake of reliability and being able for each level to help each other out, they need integration technology. That is still the evolving area.

Senator FRANKEN. Thank you.

Madam Chair, the panel has rudely used all my time by directly answering my question in a productive way. [Laughter.]

Thank you. I will submit questions for the record.

The CHAIRMAN. Great, thank you, Senator Franken.

Senator Portman.

Senator PORTMAN. Thank you, Madam Chairman.

Don't you hate when they do that? You know, actually provide great information? [Laughter.]

First of all thanks for holding these hearings. This, as you know, is a hearing that is part of the comprehensive look at energy, and I am excited about being a part of it. I thank the Chair and Ranking Member for bringing us together last week on energy efficiency and this week on infrastructure, two really important topics.

Last week we talked about a whole bunch of bills including S. 720, which is the Shaheen/Portman now Portman/Shaheen bill. We are pleased to have heard from the Chair that we are going to be able to have a mark up on that legislation.

Today there are a whole bunch of great bills including the Chair's bill, S. 1225, I think has a lot of promise. Senator Hoeven's bill, S. 1228 with regard to permitting.

What I am hearing today from you guys is there is going to be a whole lot of opportunity here for some exciting infrastructure projects around the country related to energy, and we have to get it moving.

Jim, I appreciate your coming back before this panel again. You came in at the request of Senator Manchin and myself to talk about reliability, and I listened carefully to your comments today on that. It is about jobs, and it is about grid reliability in terms of these regulations.

On the permitting front these investments that you all are talking about, billions of dollars of energy infrastructure are running into real problems which are that our permitting system in this country is way out of date. If you look at the World Bank study they do every year, what the best place to do business, the ease of doing business? We now rank 41st in the world in terms of siting projects. And I am not just talking about energy. I am talking about any kind of permitting.

I have joined with a bunch of my colleagues, including Senator King who I see here across from us, Senator McCaskill and others to put forth a bipartisan bill to streamline this process, consolidate it and make sure that we are not falling behind. This first came to my attention, frankly because of an energy project in Ohio. It was a hydro plant along the Ohio River, and I learned that some energy projects have as many as 35 different Federal permits you have got to go through. We have heard a lot about that today. So my goal today is to try to figure out, how do we help with regard to energy? But it is broader than that.

I had a company come see me last week. They are trying to build a pipeline. You know, we have got some real energy possibilities in Ohio now with Utica and Marcellus.

They told me that in order to build the project that they would like to build in my state which would be a great benefit to our economy, they would be required to secure up to 1,900 separate permits from multiple Federal agencies including FERC, the Army Corps of Engineers, Fish and Wildlife, NOAA, Forest Service, BLM, National Park Service and so on. Frankly the uncertainty around that, the time commitment to it and the legal liability potential, you know, the statute of limitations being six years and so on, makes it very tough for them to get the kind of investors they need to move forward on that.

So I would encourage you all to look at S. 280. We introduced it again this year, Senators Manchin, King, McCaskill and others, and we had it marked up last week in the Governmental Affairs Committee. The markup after some work over the last several months with OMB and others ended up being a 12 to 1 bipartisan vote. So I hope it can be part of this broader package we are talking about.

It goes beyond just energy, but it relates directly to what we have heard about today. Dr. Kalk and Ms. Bowman both have talked about deadlines for requested reviews for instance today. That is one of the big parts of this legislation.

So my question to you, Amy and to you, Erica, because you have got some Buckeye roots, I have to ask you a question being an Ohioan. Would this help? I mean, you testified that the electric industry is undergoing this transformation and all the reasons for it. We know some are market-based. Some are government policy-based. Do you have concerns that the permitting system might delay or even jeopardize the construction of some of this new infrastructure that we need?

Maybe we could start with you, Erica?

Ms. BOWMAN. I absolutely do think that permitting streamlining is required and needed. At least on the pipeline side of things, we're really experiencing, it's not only about permitting, but it's also about activism on the other end. And this is not about us. But we want a very transparent process. We want to maintain a good process with respect to review to make certain that all the due diligence is given and that whatever project is before whichever agency that they have the time that they need to do the analysis correctly.

But what's really happening, at least from our perspective, is that we're getting a lot of activism that really, it's not about the project. It's about ideology, and that becomes very difficult. And they're using the regulatory process as a way to hamper development. And that's something that we really need to move beyond as much as possible.

Senator PORTMAN. Ms. Ericson.

Ms. ERICSON. Yeah, I think that the grid accommodated policy and regulatory changes in the 80s and 90s. It needs to continue to evolve to be flexible and be able to accommodate future changes.

I'll just remind you as we move in the concept of an integrated grid for the purposes of sustainability, reliability and affordability,

we can't think about all of those different levels in isolation. We have to look at them as an interconnection, and all of those systems will be interconnected.

So to answer your question I think that the policies that are affecting them need to be interconnected too. Be it in the permitting area, in all areas the policies need to be interconnected as well across the Federal, state, local levels.

Senator PORTMAN. Thank you. Thank you, all.

Thank you, Madam Chair.

The CHAIRMAN. Thank you.

Senator King.

Senator KING. Thank you, Madam Chair.

First Ms. Ericson, of all the witnesses I have ever seen, you are the first one that hit the five minutes right on the nose. [Laughter.]

You are obviously a very well organized person.

I want to associate myself with Senator Portman's comments as someone who has worked in the energy field for over 30 years. I know about permitting and how it can, I believe, unnecessarily delay projects. We can have the bio way set in Maine. I wanted the toughest environmental laws in the country but the most timely and predictable permitting process. And I think you can have those two things. A timely and predictable, environmental permitting process is, in no way, inconsistent with environmental protection.

Second, I just want to mention, Madam Chair, because this is a hearing on the bills that are coming up. One of the bills that I have submitted is a bill that would limit natural gas exports, essentially, to ten percent of domestic production. The basis of that was testimony that we had at a prior hearing on behalf of the idea of exporting natural gas. I am gravely concerned about unlimited exports adversely affecting prices in our domestic market. The ten percent figure came from the testimony of the advocate for exporting who assured me when I asked him, will this affect domestic prices? He said, "all of our studies say it will never exceed nine percent of domestic production and there will be a minimal effect on consumer prices in the U.S." So I took him at his word and wrote a bill to that effect. That is the origin of that, and I think this is a very important issue. I am not opposed to exports, but I think we need to be very, very cognizant of possible impacts on domestic manufacturing and our domestic consumers.

Thirdly, and I know it has been addressed in some of the testimony, and Mr. Dotson, you touched upon it. I have submitted a bill on distributed energy resources, and essentially the purpose of this bill is to provide guidance and a strategy for going forward with something that is going to happen anyway.

There is no question in my mind that rooftop solar, storage, conservation, demand response is going to happen in this country sooner than we think. The only question is whether it is going to happen in a thoughtful, deliberate, rational, process or we are going to have little brush fire wars in all 50 states.

My bill is not in any way anti-utility. I understand, as having worked in this industry, that the utilities and the rate payers need to be protected in terms of their investment in the grid and the cost of delivering the grid and having the grid, in effect, being the backup. On the other hand, what the bill talks about is that those

charges shall be just and reasonable and shall take into account the benefits of distributed generation as well as the costs. It is not one side of the ledger, and that is really the purpose of the bill, Madam Chair, because I think this is such an important issue.

It really is also a sovereignty issue. One of the first people to come and visit me when we proposed this bill was a member of the Tea Party in the Southeastern part of the United States. They view this as an individual sovereignty issue. People have a right to generate their own electricity and not be stifled by arbitrary costs and charging fixed charges in a case that would basically be designed to discourage these kinds of development. I believe that what we are trying to do here is create, as they say, a path toward a fair and rational allocation of costs.

Mr. Weisgall, you talked in the end that you said the cost should be just and reasonable. I have no disagreement with that as long as those costs are rationally and fairly applied running in both directions. I think, unfortunately, we have to move in this case from simplicity to complexity because, I believe, net metering is a good technique now but I do not think it is the long term answer. And we have to talk about unbundling rates, time of day usage, to provide the right price signals to customers in order to incent the kind of activities that will benefit both the customers and the grid making it more secure.

As a member of the Intelligence and Armed Services Committee and I'm running out of time, I am not going to be quite as good as you, Ms. Ericson, but we have got a national security issue here. To the extent that the grid can be decentralized and self healing, we are much better off from a national security point of view than the old model of the centralized grid that a cyber attack or Hurricane Sandy can take out and take out millions of people at once.

So that is my marker, Madam Chair. I think we have, if my mail is any indication, hit on something important. I look forward to working with you as we work through this bill. I think distributed energy is a huge part of our energy future in the country, and we have to be sure that we get it right.

Thank you, and if you can find a question in there you are welcome to it. [Laughter.]

But I appreciate the witnesses and appreciate your testimony. Thank you.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator King. I think we all agree we need to try to get it right.

Senator Barrasso.

Senator BARRASSO. Thank you, Madam Chairman.

Ms. Bowman, to this question of LNG exports. In your testimony you noted that the President's Council on Economic Advisors issued a report in February. Madam Chairman, I would like to introduce that report for the record.

The CHAIRMAN. Duly noted.

[The information referred to follows:]

ECONOMIC REPORT OF THE PRESIDENT

Together With

THE ANNUAL REPORT

of the

COUNCIL OF ECONOMIC ADVISERS

Transmitted to the Congress

February 2015

ECONOMIC REPORT OF THE PRESIDENT

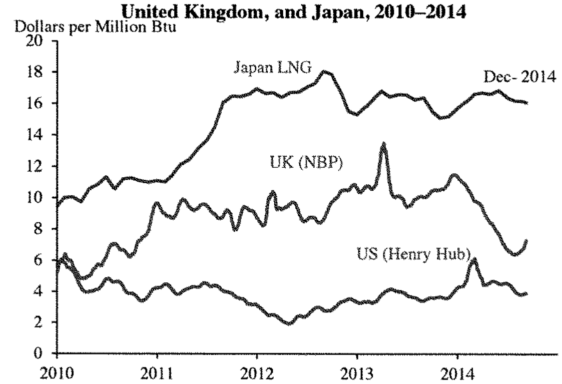
TRANSMITTED TO THE CONGRESS
FEBRUARY 2015

TOGETHER WITH
THE ANNUAL REPORT
OF THE
COUNCIL OF ECONOMIC ADVISERS

Box 6-1: Natural Gas Exports

Over the last decade, U.S. natural gas production increased by roughly 40 percent. This sharp increase in domestic production has widened the gap between domestic natural gas prices and natural gas prices in other countries (Figure 6-i), creating potential profitable export opportunities for domestic natural gas producers. In 2014, the United States surpassed Qatar to become the world's largest exporter of Liquefied Petroleum Gas (LPG),[1] for which there is already export capacity in the Gulf region for 400 thousand barrels per day (bpd), with another 700 thousand bpd expected by 2016. The Energy Information Administration (EIA) projects that the United States will become a net exporter of liquefied natural gas (LNG) by 2016 (Figure 6-ii). However, expansion of U.S. natural gas exports requires both governmental action and the construction of additional exporting infrastructure.

Figure 6-i
Natural Gas Prices in the United States, United Kingdom, and Japan, 2010–2014



Note: UK's prices do not include natural gas imported from Russia which is predominately indexed to oil prices. Japanese prices are monthly averages. All series are represented as 30-day moving averages.
Source: Bloomberg.

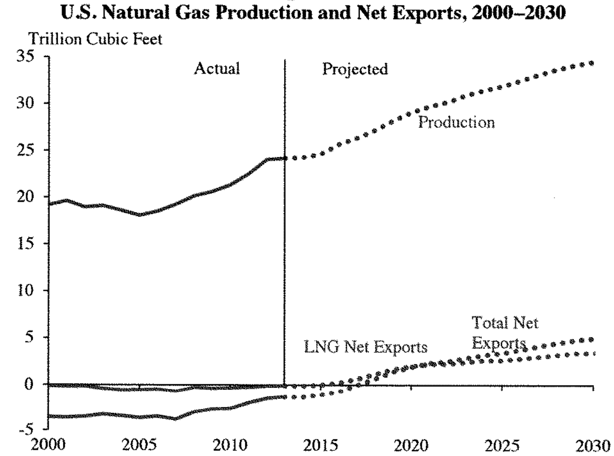
Both transportation costs and government-imposed barriers to trade have caused prices among countries to differ. The gap between U.S. natural gas prices and prices in other countries reflects two main trade impediments. First, transportation costs—liquefaction, transportation abroad, and regasification—roughly double the price of gas entering Europe relative to the price at its origin in the United States. Transport charges must cover substantial infrastructure investments and capital

[1] A group of hydrocarbon gases derived from crude oil refining or natural gas processing.

expenditure—for example, the cost of building a liquefaction terminal that can export up to 2.76 billion cubic feet (bcf) per day for 20 years can be around $12 billion.[2] The second impediment is the Natural Gas Act of 1938 (NGA) and subsequent amendments, which restrict natural gas exports. Under the NGA, natural gas exports require approval from the U.S. Department of Energy (DOE).[3] As of November 2014, DOE has approved applications for the export of about 12 bcf per day of LNG, although some of the approvals are contingent on approval by the Federal Energy Regulatory Commission. Because the recent technological developments have given the United States a natural comparative advantage in gas production over importing regions, both trade impediments – natural and government mandated – depress U.S. gas prices relative to those paid abroad.

What will happen as more export infrastructure comes on line and DOE approves higher volumes of gas exports? When barriers to trade are reduced between a low-cost country (the United States) and

Figure 6-ii
U.S. Natural Gas Production and Net Exports, 2000–2030



Source: Energy Information Administration, Annual Energy Outlook (2014).

[2] Over 15 bcf per day of export capacity is under construction or has been proposed, though cost considerations make it unlikely that all proposed projects will be completed. By comparison, the United States produces almost 70 bcf per day.

[3] Approval is even required for exports to countries with which the U.S. has a free trade agreement, though an amendment to the NGA in 1992 required that applications to authorize exports to free trade partners be granted without modification or delay. As a result, conclusion of the Trans-Pacific Partnership and the Transatlantic Trade and Investment Partnership would vastly increase the range of countries to which U.S. producers could export without administrative barriers (see Chapter 7).

high-cost countries (importers in the rest of the world), basic economic theory predicts a convergence of prices. As U.S. natural gas enters the global market, it will increase global supply and push global prices down. Meanwhile, domestic prices will rise as natural gas leaves the domestic market, reducing supply in the United States. A recent study by EIA estimates that an increase in exports of 12 bcf per day by 2020 would raise U.S. residential retail prices by 2 percent between 2015 and 2040, although the EIA considers such a large exports increase by 2020 to be almost impossible. An increase in U.S. exports of natural gas, and the resulting price changes, would have a number of mostly beneficial effects on natural gas producers, employment, U.S. geopolitical security, and the environment.

- **Higher prices for domestic producers increase domestic production.** Increased production, in turn, spurs investment, increasing U.S. GDP. EIA (2014) estimates that the increase in GDP could range from 0.05 percent to 0.17 percent in different export scenarios ranging from 12 to 20 bcf per year, phased in at different rates beginning in 2015.
- **An increase in exports can create jobs in the short run.** Estimates suggest that natural gas exports of six bcf per year could support as many as 65,000 jobs (Levi 2012). These jobs would arise both in gas production and along the supply chain (for example, in manufacturing machines and parts used as downstream inputs).
- **Lower natural gas prices around the world have a positive geopolitical impact for the United States.** Increased U.S. supply builds liquidity in the global natural gas market, and reduces European dependence on the current primary suppliers, Russia and Iran.
- **More U.S. exports could help promote the use of cleaner energy abroad, including in developing countries that now rely heavily on coal.** Lower foreign emissions would help to counteract global warming and therefore are a direct benefit for the United States. As natural gas becomes cheaper for the rest of the world, countries overseas will replace dirtier, coal-fired power with natural gas. Cheaper natural gas could also replace low-carbon sources and increase electricity consumption abroad; the net global impact is ambiguous. The effects of the natural gas price increase in the United States are also complex. Higher gas prices tend to curb overall emissions by reducing total energy consumption and inducing substitution toward renewable sources of power. However, higher prices might also cause some U.S. substitution toward coal, raising our emissions.
- **U.S. manufacturers would still have a competitive cost advantage in natural gas, albeit smaller than what they would otherwise have.** Because of transportation costs, in equilibrium, U.S. natural

gas prices would still be expected to be persistently lower than prices overseas. The cost advantage, however, would be smaller than it would otherwise be—but any potential impact on manufacturing is likely to be small because in 2010, on average, the cost of natural gas represented less than 2 percent of the value of manufacturing shipments. This suggests that a 2 percent increase in the price of natural gas would raise average production costs by only about 0.04 percent. For the most intensive users—such as producers of flat glass or nitrogen fertilizers—the increase in costs will be higher. But these gas-intensive industries represent only a small share of total manufacturing employment and output. In particular, the top 15 gas-intensive industries account for only 2 percent of total manufacturing employment and 3 percent of manufacturing value added. Businesses with very thin profit margins may also be adversely affected. In contrast, expanded natural gas exports will create new jobs in a range of sectors including natural gas extraction, infrastructure investment, and transportation.

households—have also benefited from the slower growth of electricity prices caused by lower wholesale natural gas prices.

Oil prices decreased dramatically in the second half of 2014. Box 6-2 shows the drop in crude prices, and notes the range of global factors behind the drop, including the boom in U.S. oil production. Retail gasoline prices are closely linked to global crude oil prices, so households now pay less for gasoline. Seasonally adjusted gasoline prices decreased by roughly $0.80 per gallon between June and December 2014. EIA estimates that lower gasoline prices in 2015, compared to 2014, will save the average household about $750. Oil-consuming businesses would also enjoy huge gains—in the tens of billions of dollars. In addition, the fact that lower oil prices are expected to boost the global economy will create additional spillovers for U.S. economic activity by creating higher demand for the products and services we export. On the other hand, these gains are partially offset by the fact that lower crude oil prices reduce the profits and investments of oil producers. On net, however, the recent oil price decrease benefits the U.S. economy (see Chapter 2 for further discussion of the macroeconomic effects of oil prices).

Senator BARRASSO. It discussed the benefits of LNG exports. Could you just briefly explain exactly what President Obama's Economic Advisors had to say about LNG exports?

Ms. BOWMAN. Sure. So they noted many benefits to the export of LNG. One of which was that with LNG exports coming from the United States to other areas of the world it's going to increase domestic production. So all the economic benefits that comes from increased production will flow back to the United States economy.

Additionally it found that by the U.S. exporting to the global marketplace it would reduce LNG prices worldwide which really creates some geopolitical advantages to the United States because we become a much larger player in the energy landscape of the world.

Additionally, it talked about when LNG from the U.S. is used regionally across the world and it's displacing coal generation that it has the opportunity for emission reductions.

I think the one thing that the Council didn't talk about but there is a study done by the National Energy Technology Laboratory where it's not just about displacing regional coal across the—or across the world, but rather also regional gas from Russian pipelines because their pipelines are very leaky. And by delivering U.S. LNG to Europe and to Asia you actually have a net GHD benefit.

Senator BARRASSO. Thank you.

Ms. BOWMAN. But additionally to that one thing too that while they talked about the increased domestic production they also mentioned that the U.S. manufacturing renaissance would not be hurt by the start of U.S. LNG exports.

I think one thing that can be offered with respect to that too is that when you increase your domestic production of natural gas you're also bringing out natural gas liquids as co-products. And because you're increasing the supply of those natural gas liquids, you're basically creating a more stable price for those feed stocks to the U.S. manufacturing companies which really leads to stability and encourages the renaissance that we're seeing.

Senator BARRASSO. Great, thank you so much.

I also wanted to touch on my bill, S. 411, the Natural Gas Gathering Enhancement Act, and related legislation. The fact is the United States, I think, needs more oil and gas pipelines. We are the world's largest producer of oil and gas, and we need a safe and reliable way to transport this energy to market, as a number of you have testified. We need more pipelines where oil and gas is produced in states like Wyoming and North Dakota, but we also need more pipelines where the oil and gas is consumed including New England.

I think it is fair to say that the permitting process that we have heard today for pipelines is broken. After more than 6½ years we still do not have a decision on the Keystone XL pipeline. This is absurd.

But over the last five years we have seen significant amounts of natural gas vented and flared in states like North Dakota while New England continues to experience a shortage of natural gas, and this results in some of the highest energy prices in the country. Senators Heitkamp, Hoeven, Enzi and I have tried to address this problem by making it easier to capture natural gas that would

otherwise be vented and flared. The bipartisan bill expedites the permitting process, gives some certainty for natural gas gathering lines. I think it is critically important.

My question, Ms. Bowman, is will you discuss some of the obstacles that oil and gas producers are facing today when siting gathering lines on Federal and Indian land.

Ms. BOWMAN. Sure. And really the main obstacle there is is the timeline for the permits. So the right of way permits, traditionally, have taken about four to six months. And then you have the sundry permits as well. They're a little bit less intensive, and they have historically taken around two to four months to get through the approval process, or the permitting process I should say. But recently those times have significantly increased to more than doubling. So you're waiting six, you're waiting 12 to 14 months, and you're waiting up to a year for a sundry permit approval.

Given that in these areas that you have a lot of co-products coming from the well so you may be, actually, directing your well towards oil, you will drill that well. You don't have the gathering lines in place, so you are flaring that associated gas. Well, that doesn't lead to anything good in any real way because you're denying the consumers the benefits that come with natural gas. So by basically increasing your permitting time while maintaining the proper review process, you're able to deliver a very clean fuel to customers that delivers cost savings and environmental benefits as well as energy security. So it makes a lot of sense to get the permits moved through the processes as quickly as can be given the timelines that are currently there.

Senator BARRASSO. Thank you.

Thank you, Madam Chairman.

The CHAIRMAN. Thank you.

Senator Hoeven.

Senator HOEVEN. Thank you, Madam Chairman, and I want to welcome all of our witnesses.

In particular I would like to welcome Commissioner Brian Kalk from North Dakota. PSC Commissioner Kalk was a distinguished Marine with a 20-plus year career in the Marine Corps. He retired, I believe, with the rank of Major, and did an outstanding job serving our country both here at home and overseas. He has been elected to our PSC a number of times and does a tremendous job, and he also has instructed at North Dakota State University on energy and other issues. So Commissioner Kalk really brings tremendous expertise in the field of energy.

I guess where I would like to start, Commissioner, with you is we need energy infrastructure to build the right kind of energy plan for this country, and that is a real challenge. I sponsored the Keystone XL pipeline legislation which we passed in the Senate with well more than 60 votes. The President has vetoed that legislation and held the decision up for six years.

So talk for just a minute about how we can build the kind of energy plan that we need for this country? How are we stimulating that investment in North Dakota, and how can we generate that in—and again, it's private investment building, a lot of this infrastructure? How do we get this infrastructure going? What are you doing in North Dakota? What can we do nationally?

Dr. KALK. Thank you, Senator, for the question.

I guess, to dovetail a little bit, Senator Murkowski questioned me about the NEPA process and expediting that. That's a big piece of it. On the pipelines particularly, in North Dakota we've held numerous hearings on pipeline infrastructure. We've held the hearings of approved projects. There's border crossings from North Dakota to Canada that are being held up by the current Administration.

And one thing that we've got to have is the pipelines to be able to move the product from North Dakota to other parts of the country whether it's crude, whether it's natural gas. We're able to do the work right now in the state, but it's very frustrating when we don't have the approval to move it outside of our borders. It's not only Canada. We're having some challenges in Minnesota, quite honestly, and South Dakota. That's just the way it works. But anything that we can do to get the pipelines built. Pipelines are, by far, the safest way, the most efficient way to move a product. Until we get the pipeline infrastructure built, we're going to have stress on our roads from trucks and safety concerns. You've seen rail concerns because of capacity. The pipelines are absolutely critical to be built, and that's where it's very frustrating.

I think that one of my colleagues, down the way, talked about the will. You have to have states that have the will to build the infrastructure, and they have to truly believe it's good for the nation. That's where I think it comes down to get the data, make the decision and move it forward.

Senator HOEVEN. So, the issue is delay, right?

I think you have made that point clearly as have others. In many cases this is private investment, billions of dollars, vital energy infrastructure we need, to move product more cost effectively and more safely and the problem is delay on the part of the Federal Government. Right? So legislation that we are putting forward, like my North American Energy Infrastructure Act and the Keystone legislation, the legislation of Senator Barrasso, our Chairman. All of this legislation that has been brought up today, that is designed to cut through this delay and that would make a significant difference in your opinion, in terms of both moving energy more safely and more cost effectively?

Dr. KALK. Yes, Senator, I believe that is the case.

I would even add that in North Dakota we work with the companies. If we've got a concern about a certain river crossing or certain safety concerns, we'll ask the company, extra shut off valves and increase their emergency response plans, and they always do it.

So in these agencies causing the delay, if there's something they don't like, they need to say what the companies need to do to fix it. We don't automatically approve things. We bring out the concerns and they address them.

Senator HOEVEN. So one issue is delay, and that is a huge issue which we need to cut through.

The other is duplication, and what I want to bring up as an example is the fracking rules. I want to talk about the fracking rules in North Dakota and now the Department of Interior has come with a whole Federal regime on fracking, so now the energy producer faces duplicate regulation. Wouldn't it make sense to have

just one regulator? Have the state be a primary regulator? And if they are covering the issues as far as safety and transparency, wouldn't it make more sense to have one rather than duplicate that regulation?

Dr. KALK. Absolutely, Senator.

North Dakota was the leader in setting up fracking rules. We were also a leader in putting up CO_2 storage and pore spaces. We've done the things we need to do in the state, and we've created the certainty in the state, but people need to do things. When the Federal Government comes out with additional layers that contradict the states, that's not the way this is designed. I talked in my testimony about states' rights and about we have to do things as a state. That's the way it should be, and I agree with you, Senator.

Senator HOEVEN. You said a very important term there, "certainty". So we can get billions invested, a growing economy, and job creation by giving certainty to industry so they can make that investment. So that's what you mean when you say certainty, right?

Dr. KALK. Absolutely, Senator. And it's not only the company's certainty, it's the ratepayers and those who use the products. They should be able to know that the price of gas is going to stay in a certain range. They should be able to know they're electricity costs are not going to spike. And we've got these projects that get held up. You know, we have a growing need for power in North Dakota. The country always needs more energy. So it's not just a certainty for the investors. It's certainty for the ratepayers.

Senator HOEVEN. And also protection for ratepayers and customers in terms of, again, talk about the hydraulic fracturing. I mean, you require transparency. You require that they use frack focus. You require that they have integrity in their wells and the cement seals and all those things. The very same things now that the Department of Interior is calling for in their regulation. Isn't that the case?

Dr. KALK. That is absolutely correct, Senator. The state continues to do a good job, and our biggest threat is not anything other than the Federal Government in our energy development.

Senator HOEVEN. Thank you, again, to all of you, thank you for being here, particularly our Commissioner, thank you.

The CHAIRMAN. Thank you, Senator Hoeven.

Senator Flake.

Senator FLAKE. Commissioner, sticking with you for a minute and kind of on the same theme. We have heard other members say that or discuss the Federal Government coming in and establishing utility rates in certain areas. You, in your testimony, dealt with some of that. Do you want to elaborate? Who is in the best position to determine what those rates ought to be?

Dr. KALK. Senator, I always believe the states are in the best position to do that, and it is becoming increasingly challenging, not only with potential Federal rules, but different states have different policies. And that's their right. I respect that. But it becomes challenging when a certain state passes a renewable mandate and that state builds the infrastructure no matter what the cost and need is. And you've got an integrated grid which then that power then flows to neighboring states. This is a very big challenge.

And so it goes back to state regulators have to understand what the impact is to their ratepayers. They have to develop the renewables as appropriate, but we can't forget about base load power.

We talked about reliability and sustainability of the grid. The coldest day in North Dakota, the wind is not blowing. When we have these biggy weather events, it's base load power that gets us through those.

Senator FLAKE. Mr. Dotson, you mentioned that some of the cost now imposed on solar is dampening demand or enthusiasm for solar.

Mr. DOTSON. That's right.

Senator FLAKE. But we recognize and other testimony has said that we have got the grid to worry about. Somebody has to maintain it. How would you propose that be done if it is not charged to solar customers?

Mr. DOTSON. Thank you very much for the question.

I think, I wouldn't preclude any charge to customers, but I would say that I think the public utility commissions are best suited with what's the appropriate rate structure to ensure that we are getting rooftop solar deployed, that people do have that option at the same time that we're able to allow electric utilities to function.

Senator FLAKE. So that, but that speaks to the utility commissions at the state level making that decision——

Mr. DOTSON. Yeah and I think there could be a stronger Federal role. I mean the Federal Power Act of 1935 established this line between Federal regulators and state regulators and left retail sales largely to the state regulators. But there's a lot of issues that are now blurring the lines whether it's cyber security, smart grid or this issued of distributed generation. And so, Congress, there's no constitutional reason that Congress can't consider this.

The Supreme Court in Mississippi verses FERC examined this and said certainly Congress has the authority to step in on a retail issues where appropriate. And if you look at other issues, for example, real estate transactions where that's also traditionally a state issue, but when the Federal Government has found problems they've been able to step in whether it's lead based paint or whether it's disclosure of home mortgage products. And this is an example where, I think, it's not inappropriate for Congress to think about what is the best approach to ensure we're getting an outcome we want.

Senator FLAKE. Anybody else have thoughts there? Go ahead.

Mr. HUNTER. Well, I think our biggest issue always, and understand IBEW installs solar. We install wind. We're not in any way anti-renewables. But we have to have the grid working, and we can't install. We've got a problem right now in Hawaii where there's so much solar installed the grid simply is not working. And you still have to sit there as soon as the sun goes down, have the available power.

And what we're seeing in many, many states now is that, especially when it's deregulated, your generation is sitting there all day long not getting paid, not earning any money, and as soon as the sun starts to drop, which is normally the same time that you hit your peak load, all this generation is required on the grid. So how

we phase those in together and how we make the grid work, I think, is what we feel is very important.

Senator FLAKE. Thank you, Madam Chair.

The CHAIRMAN. Well this is probably the question of the hour here or the hours, and I think we recognize that we are at this very interesting point in time. We have had a system in place for decades, if not more, where you have your utilities that provide for the power and your obligation as the consumer or the ratepayer is to pay your bill once a month.

Now with this whole concept of distributed generation and what an individual may be producing on their own, Senator King used the term, said that this was an issue almost of sovereignty. It is my right to be able to generate my own power. I think we do need to acknowledge that you may want to generate your own power through your rooftop solar, but then when that does not provide you everything that you need, you still want the benefits that the grid has provided.

So those who do not have the rooftop solar panels, in effect, are ending up subsidizing those that can afford to put the rooftop solar on their homes.

So how we balance all these, I think, is so much of the discussion that we are at today, and it is not something that we have had to wrestle with in years before. When we were dealing with the last energy bill that this Committee had in front of us, we were just not at that place where we were all talking distributed generation and the impact on reliability and security of the grid. So this is why, as much as anything, this discussion that this Committee is engaged in right now and some of the decisions moving forward are so critical because things are changing.

Mr. Weisgall, do you want to jump in here?

Mr. WEISGALL. Well, the dilemma reminds me of a comment that the former chairman of this Committee made which was, you know, everybody wants to go to heaven. Nobody wants to die. [Laughter.]

And it's a real challenge of how we get there.

With respect to Senator Flake's question, I mean, one thing the utilities are coping with is, you know, we hear our customers. They want solar. They want that sovereignty.

We're working on utility scale solar. We're working on community solar. That's another whole big topic where, again, we're looking at how can we accomplish this in the most affordable way to customers, as Ms. Ericson has said. That's our job as a utility, to get that energy in the most affordable way and keep it reliable as well.

So you're absolutely right. Those are the challenges, but I think some of the proposals you have here today are the best ways to tweak those.

The CHAIRMAN. This is not easy, but nobody said it was going to be easy when we started, so we will just keep working through it.

Ms. Ericson, I wanted to ask you a question about the interoperability standards. As you know back in the '07 Energy bill, NIST, the National Institute of Standards and Technologies, through the stakeholder effort, was asked to produce interoperability standards. FERC then was supposed to adopt the NIST standards upon a finding of sufficient consensus, but there were a couple of technical

conferences and the Commission basically came out and said we don't have sufficient consensus here for these NIST interoperability standards due to opposition from industry, due to cyber issues.

So the question that I would have for you this morning is whether or not you think it is still important. Is there a need for a smart grid interoperability standards today? What might they look like? What would the process look like after what we saw with the failure of the earlier attempt?

In response to somebody's question previously you said, look, everything needs to be knit together. So I am assuming your answer is going to be yes. If so, how would you envision that process going forward?

Ms. ERICSON. You're right. My answer is yes. Interoperability is still a good idea, and we do work with the Office of Electricity in DOE. We work with NIST. It is difficult with the different players and this whole vast structure to get consensus but I think we just have to come back together again and try it with the leadership of the Department of Energy, with the leadership of NIST and frankly, with the leadership of some of the state and local authorities. But yes, we have to do it.

The CHAIRMAN. Okay.

Ms. ERICSON. The interconnection, both the benefits and the risks associated with the interconnection, will be better with this interoperability capability.

The CHAIRMAN. I appreciate it.

Senator Risch, you have returned.

Senator RISCH. Thank you very much, I have returned.

First of all, Mr. Weisgall, I appreciate your comments about moving the goal post by the government as you try to get through one of these things. Of course, it is a fallout from two different things.

Number one, the permitting process takes so long. Secondly, the people who do that change and the philosophy changes and that is what happens when you are a government of people instead of laws. A new person comes into the position, and the goal post gets changed, and we are seeing that. We see it over and over and over again, and it is incredibly frustrating for people trying to do business.

I am going to talk just very briefly, Madam Chairman, about the bill I have proposed, Senate bill 1037, which is a bill that expands the provisions for termination of the mandatory purchase requirements under PURPA.

PURPA was enacted by Congress in 1978, and it was designed to increase our energy independence at a time when we were in a real energy crisis. To that end, of course, the PURPA law required that utilities purchase power that was generated by non-typical traditional utility companies, and it was required to be purchased at full voided cost. Of course, the purpose of that was to attempt to generate more electricity which it did.

At the same time the Federal Government, over a period of years, enacted massive financial incentives to the tax code which spurred incentive in different types of energy projects.

Now you had two things going on. Number one, the utilities were forced to purchase the electricity that was generated. Secondly, it

was required to be purchased at full voided cost. Thirdly, you had the incentives with the tax code which worked incredibly well.

We have gotten to a point that no one imagined. It is hard to believe that they passed a Federal law with people not being able to see all the things that could happen as a result of it. They passed this Federal law thinking that we would always need every kilowatt of electricity that was generated. Now the need is not what was not covered in the original law, but is now something that should be considered.

What this bill does is it brings need into the equation, and its need to be determined by the state public utility regulators which, Dr. Kalk will be happy with, but if you worship at the altar of a strong, central government that should control everything, you will not like. In any event it now puts needs into it.

The best example I can give of this law of unintended consequences which has bit us is that our local utility in Southwestern Idaho, Idaho Power, has no need for additional generation until 2021. Yet at the same time they have had as many as 73 proposed, mandatory purchase solar projects that it has exceeded a thousand megawatts that they had to deal with. So the combined cost to the customers of Idaho Power would have been $2.7 billion. What has happened is the consumer, as always, winds up paying the whole tab. At one end they are paying these tax subsidies to get people to go out and generate this electricity, then at the other end they are paying as a customer of the utility for the energy that was generated at this full voided cost. So it is the consumer who is really picking up the tab here, and this is designed to change that. It is designed to shift this over, to a large extent, to the states.

I know it is going to come as a horrendous shock to people in this town, but the states actually can make these kinds of decisions and in the best interest of their local utility. This is what happens every time the Federal Government muddles in the free market system, and it always happens when the government tries to pass a one size fits all rule which is exactly what this is.

So that is what this does, Madam Chairman, and what it does is recognizes the reality of today's marketplace.

Thank you very much.

The CHAIRMAN. Thank you. I appreciate your leadership on that.

Would anyone care to respond to Senator Risch's comments?

Mr. WEISGALL. One quick footnote. I think the bill is an excellent one. I agree with all of your comments. One of our utilities is in the identical position of Idaho Power.

I would only suggest you look at one criterion, which is need. Our proposal looks at other criteria as well. Is there a competitive market out there for a QF? Are there competitive solicitations? If there are, there's just no need for this mandate. So we would urge you to use your bill as a starting point and look at other suggestions out there that are complementary to what your bill does and in no way would contradict what you're trying to do.

Senator RISCH. Madam Chairman, first of all, I think that is a really good suggestion. I certainly have no pride of authorship in this, and I am willing to look at other things. The playing field has changed since 1978, and that is what this is aimed at and it is aimed at trying to pick up some of the realities that are out there

in the marketplace today. Thank you for that input, and look forward to further input from you.

Thank you, Madam Chair.

The CHAIRMAN. Senator Risch, thank you.

Senator RISCH. Does anyone else have a comment?

The CHAIRMAN. Yes, does anyone else want to weigh in?

Senator RISCH. Thank you.

The CHAIRMAN. Thank you.

We have a couple of votes that are coming up here in just a few moments.

Mr. Hunter, I did not ask any questions of you, but I want to thank you also, again, you came before this Committee before. I think your testimony contributed significantly to what we had in front of us about a year ago when we were discussing the issue of reliability. I also think not only the comments that you have provided in your written testimony, but your comments here before the Committee today are a plain truth on this; when we are talking about reliability and affordability, you are not only speaking from the perspective of representing those men and women who make things happen on the job, on the ground, the jobs that are associated with these energy infrastructure issues. You also represent those men and women that when they get these statements every month they pay attention to them because how much they are paying on a monthly basis matters to them and their family. When it goes up a little bit you can deal with it a little bit, but when it goes up considerably this has impact.

I think far too often as we talk about the amazing changes that are going on right now within the energy sector and the great excitement about the possibilities that we have for a newly imagined energy future, it is all very exciting. It is all very dynamic, but I do not want us to get carried away with the excitement and forget that affordability has to be a critical component, an absolutely critical, if not the driving piece of this.

In my State of Alaska we have some of the highest energy costs in the country, and I want to figure out everything that I can to bring renewable opportunities to them, to bring innovative energy opportunities to them, to figure out how we work this whole micro grid concept so that it is real and meaningful and lived out in our communities.

But at the end of the day if I promise them this great new technology, their first question to me is going to be how much is it going to cost? Because if it is a heck of a lot more, come back when you can get the price down, Lisa. So these are so many of the considerations that we have in front of us.

Senator Cantwell, we have wrapped up on this side, but I know you have been over in the Finance Committee jumping back and forth, as have many of our members this morning. So I will give you the last round.

Senator CANTWELL. Thank you.

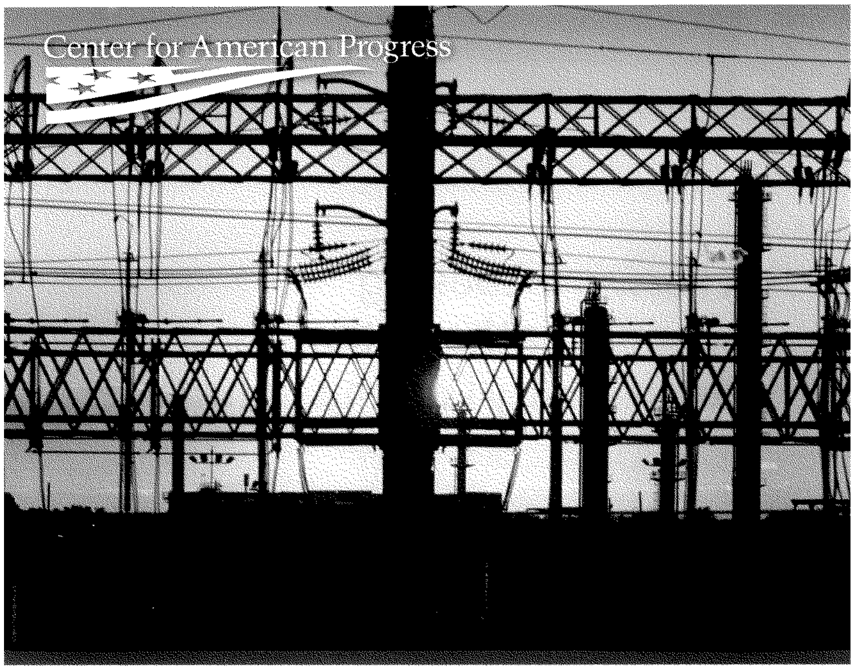
The CHAIRMAN. And you may wrap up as you see it.

Senator CANTWELL. Well, thank you.

I just wanted to add a couple of things. Mr. Dotson's organization has authored a report on PURPA, and I hope we can submit that for the record.

The CHAIRMAN. We will put it in.

[The information referred to follows:]



A Forward-Looking Agenda for the Nation's Public Utility Commissions

By Greg Dotson and Ben Bovarnick May 2015

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Introduction and summary

The electricity sector in the United States is experiencing a period of dynamic change. Technological advancements are making energy available from new and innovative sources and offering an array of new and exciting tools for managing and understanding the way that Americans use energy. Market forces are pushing natural gas in and backing coal out, while renewable energy is increasing its share of the national market. Regulations, such as the proposed Clean Power Plan, are beginning to chart a course to a low-carbon future. Furthermore, the reality of climate change is barging onto the scene for the electricity sector, bringing with it challenges such as additional strain on the nation's water supplies, which are relied upon for cooling coal-fired and nuclear power plants and turning hydroelectric turbines.

Historically, electric retail markets have been regulated at the state level, but the challenges facing the electricity sector from a changing climate, powerful market forces, and the need to reduce pollution are of such importance that the federal government has a strong interest in ensuring they are met. Unfortunately, states' responses to these challenges to date have been uneven. Some state public utility commissions, or PUCs, have been tempted by short-sighted arguments to undermine successful regulatory policies and pretend the challenges of the day do not exist. Others are working overtime to surmount the challenges that the nation faces to create an affordable, reliable clean energy future.

Over the past four decades, Congress has periodically amended the Public Utility Regulatory Policies Act, or PURPA, to call upon state PUCs to consider adjusting their electricity policies using an open and evidence-based review process. By simply requiring PUCs to examine the merits of various policies through formal proceedings, PURPA has triggered states to adopt smart policies that have helped save energy and promote renewable energy.

Congress should embrace this precedent and help set a forward-looking agenda for the nation's PUCs to address the important issues facing the electricity sector today. Specifically, Congress should amend PURPA to require state PUCs to consider three policy standards:

- Boost energy-efficiency efforts through technology and regulation.
- Establish policies to encourage utilities to use clean energy to reduce pollution.
- Ensure utilities will have the resilience to function reliably in the future.

Time of change and challenge

Industry leaders, government officials, and academics all agree that the electricity sector in the United States is experiencing a period of dynamic change and challenge. According to the U.S. Department of Energy, or DOE, "the U.S. electric system is currently at a strategic inflection point."[1] In a recent landmark report, the DOE stated:

> *The U.S. electricity sector is being challenged by a variety of new forces, including a changing generation mix; low load growth; increasing vulnerability to severe weather because of climate change; and growing interactions at the Federal, state, and local levels. Innovative technologies and services are being introduced to the system at an unprecedented rate—often increasing efficiency, improving reliability, and empowering customers, but also injecting uncertainty into electricity-grid operations, traditional regulatory structures, and utility business models. Modernizing the grid will require that these challenges be addressed.*[2]

Of course, these challenges are not lost on the industry. For instance, one leading utility executive has called for new business models for electric utilities, saying:

> *We don't know exactly what the electric power business is going to look like in 10 or 20 years. But it seems clear that the way power is generated, distributed, and used is likely to change a great deal. We have to look for opportunities to find new and better ways to serve our customers—starting now.*[3]

The U.S. electric sector is estimated to require $2 trillion of investment over the next 20 years.[4] An interdisciplinary study by the Massachusetts Institute of Technology, or MIT, found that the U.S. electricity grid will face "serious challenges in the next two decades that will demand the intelligent use of new technologies and the adoption of more appropriate regulatory policies."[5]

Three key challenges for electric utilities involve the need to build resilience to a changing environment, to reduce carbon pollution in the future, and to incorporate new technology into an evolving electric grid.

Challenge: Building resilience to climate change

Scientists warn that climate change will have tremendous impacts on human health, the environment, and the overall economy, including key infrastructure that supports our quality of life. The electric-power sector will not be immune to the impacts of climate change and, in fact, is already feeling the effects. From 2003 to 2012, the United States experienced 679 major power outages due to extreme weather.[6] However, climate change is increasing the frequency and severity of extreme weather events. This in turn increases the risks to electric infrastructure from flooding driven by rising sea levels, water shortages worsened by droughts, and heat waves that stress the grid. Utilities must consider new investments and approaches to resilience that adequately meet these threats.

Coastal utilities are projected to experience more frequent flooding as rising sea levels increase the likelihood that facilities will be inundated during storms. The most recent National Climate Assessment found that rising seas will increase the number of electrical substations along the Gulf Coast that are vulnerable to storm surges from a Category 1 hurricane by almost 25 percent, from 255 substations today, to 337 substations by 2030, to as many as 400 substations by 2050.[7] A similar study found at least six power generation facilities worth a total of $80 billion; it also found that $250 billion in transmission and distribution assets from Texas to Alabama are at risk, with more than $1 trillion in energy assets in danger. These costs could be mitigated through proactive investment, however; approximately $50 billion in invested resilience retrofits over the next 20 years would avoid losses worth $135 billion.[8]

Elsewhere in the country, persistent heat waves and droughts threaten power plant operations and electrical distribution efficiency. Many power plants rely on outdoor sources of water or ambient air to cool their thermoelectric generators, and excessive or persistent high temperatures disrupt these operations. In August 2012, the water temperature in Long Island Sound was higher than allowed for the cooling of Unit 2 at the Millstone Power Station, in Waterford, Connecticut—the only currently operational nuclear power plant in New England—forcing it to shut down 800 megawatts of power, or 40 percent of the plant's capacity, for two weeks.[9] In addition, many power plants rely on freshwater sources that will be strained by rising temperatures and droughts. Thermoelectric-power generation in the United States uses more than 200 billion gallons of water per day, about 40 percent of all freshwater withdrawals, and 25 percent of U.S. electricity generation comes from counties expected to have at-risk water supplies by 2030.[10]

Challenge: Cutting carbon pollution

Nationally, generating electricity resulted in more than 2 billion metric tons of carbon pollution in 2014, nearly 40 percent of all energy-related carbon dioxide emitted that year. More than three-quarters of these emissions came from the nation's aging fleet of coal plants.[11] To effectively respond to climate change and avoid its worst effects, these emissions must be reduced. In 2014, the Intergovernmental Panel on Climate Change stated, "Decarbonizing (i.e. reducing the carbon intensity of) electricity generation is a key component of cost-effective mitigation strategies in achieving low-stabilization levels (430–530ppm CO2eq)."[12] While U.S. carbon emissions from energy consumption in 2012 reached their lowest levels in the past 20 years,[13] continuing this reduction will pose a number of technological, infrastructure, financial, and operational challenges.

Cheap natural gas has prompted significant fuel switching in recent years. From 2009 to 2012, electricity generated from coal in the United States decreased from 44.4 percent to 37.4 percent of total electricity generated, while electricity generated from natural gas increased from 23.3 percent to 30.3 percent.[14] Natural gas produces 44 percent less carbon dioxide when burned than coal, so this shift contributed to a significant reduction in the carbon intensity of the U.S. economy.[15] This market-driven switch from coal to natural gas is resulting in corresponding investments in infrastructure, which is a challenge in itself for utilities. Yet even more importantly, a laissez-faire approach to fuel switching could result in overcommitment to a fossil fuel that will not achieve the necessary pollution reductions in the future, ending in stranded investments or runaway climate change.

Additionally, clean energy has taken off dramatically in recent years, due in large part to declining costs.[16] Financial advisory firm Lazard recently found that the levelized cost of wind energy is far less than both natural gas and coal.[17] Installed wind power capacity has more than tripled in the United States since 2008.[18] The Department of Energy has calculated that the United States has wind generation capacity equivalent to 60 large nuclear reactors.[19] In 2014, Texas produced more than 10 percent of its total electricity generation from wind, while Iowa and South Dakota each generated more than 25 percent of their electricity from wind.[20] Wind is projected to contribute 5 percent of total national electricity generation in 2016.[21] In 2014, even American Electric Power—one of the nation's largest consumers of coal—invested in wind energy because of its economic attractiveness.[22]

Solar energy has also become much more competitive. In 42 of the 50 largest U.S. cities, solar power is cheaper than retail electric rates.[23] This can be attributed to both an 80 percent decrease in the cost of solar modules from 2007 levels[24] and the increasing use of innovative third-party financing tools, such as solar loans, leasing programs, and power purchase agreements from residential solar companies.[25] In 2013, Theodore Craver Jr.—then the vice chair of the Edison Electric Institute, or EEI—wrote that "members of EEI view distributed [solar] energy as perhaps the most important development currently facing our industry."[26] In 2014, California became the first state to generate 5 percent of its electricity from large-scale solar power installations.[27] This record does not even count the output of rooftop solar arrays on hundreds of thousands of homes and many businesses. Also in 2014, Austin Energy signed a 20-year contract to purchase solar power at 5 cents per kilowatt hour, lower than the average levelized cost of electricity from natural gas.[28]

As renewable energy costs continue to decline, wind and solar are expected to make additional market gains. According to the DOE, by 2030, wind energy could generate as much as 20 percent of the nation's electricity,[29] and solar could generate as much as 14 percent.[30] Electric utilities will have to consider how to plan for this significant expansion of renewable energy.

In addition to market forces, regulations at the state level are also driving utilities to adopt cleaner sources of electricity generation. States from Oregon to Montana to New York have all enacted standards to limit carbon dioxide emissions from new power plants.[31] The cap-and-trade market in California and the Regional Greenhouse Gas Initiative that Northeastern states participate in both cap regional emissions from state power sectors using market-based mechanisms to drive down emissions and encourage utilities to adopt cleaner sources of electricity.[32]

Finally, as part of a national strategy to reduce greenhouse gas emissions, the Environmental Protection Agency, or EPA, has proposed the Clean Power Plan. This initiative will require state environmental agencies to develop plans for electric generators to reduce their emissions.[33]

The EPA's Clean Power Plan

The Clean Power Plan, proposed on June 2, 2014, outlines the best system of emission reduction, or BSER, for carbon pollution from existing power plants and establishes state emissions-reduction targets based on cost-effective and demonstrated methods of pollution control.[34] The proposal grounds the BSER determination in the EPA's four key building blocks:

- Building block 1 aims to improve the efficiency of coal-fired power plants.
- Building block 2 seeks to substitute electricity generation from coal plants with natural gas-fired generation.
- Building block 3 strives to replace fossil fuel-fired electricity generation with lower- or zero-carbon generation from renewables and nuclear power.
- Building block 4 seeks to reduce overall electricity demand.[35]

The EPA uses a formula to propose state-specific carbon-pollution reduction targets based on each state's ability to apply the BSER. The EPA proposes that each state meet an interim carbon-pollution reduction goal, calculated as an average over the 10-year period from 2020 through 2029. States also would have to meet a final goal in 2030.

The policy proposal outlined in this report complements the Clean Power Plan. Although state air-pollution-control agencies have primary responsibility for developing plans to implement the Clean Power Plan, state public utility commissions likely will play a key role as well, given their ratemaking responsibilities and oversight of electric utilities.

State PUCs have tools at their disposal that state air agencies do not. They can approve or disapprove of utility investments based on their implications for grid reliability and consumer electric rates. They can establish rate structures that incentivize energy efficiency and resilience investments. And they can assess whether utility investments should be passed on to consumers or born by shareholders.

As the EPA finalizes the Clean Power Plan later this year, states, consumers, and electric utilities will turn to the state PUCs to better understand how these commissions will use their tools to facilitate a low-carbon future.

Challenge: New technologies to provide consumers with options and benefits

Renewable energy generation is not the only area where new technology promises significant change in the electricity sector. Advancements and innovation are occurring from electricity generation and transmission to distribution and information utilization. Demand-side management, energy-efficiency technologies, and energy storage will transform electricity consumption patterns, further altering electricity markets.

Integration of energy storage systems into the grid offers numerous benefits for grid reliability through voltage regulation and electric-load management. Energy storage systems can quickly dispatch electricity in the event of an unexpected power plant outage, a forecasting error by a wind or solar generator, or increased

temporary demands on the grid—for instance, a heat wave that drives up cooling needs. By increasing the use of energy storage, utilities can avoid future investment in electricity capacity reserves that would provide power only under peak-demand scenarios.[36] Today, energy storage is a relatively small part of the electricity sector. There are about 270 distributed energy storage projects in the United States, and the majority of storage capacity is from 42 pumped hydroelectric storage plants that total about 2 percent of U.S. electric-generating capacity.[37] These projects store electricity via pumped hydroelectric energy, compressed air energy storage, batteries, and flywheels.

New energy monitoring services and technologies are increasing the ability to manage electricity demand over time. For instance, demand-side management contracts between utilities and large industrial and commercial businesses have existed for decades to help utilities manage electric loads at times of peak demands, but new services and technologies are emerging for individuals to tap into these savings as well. Smart thermostats, building energy-management software, and energy service companies offer companies new ways to reduce their electricity consumption. Federal regulators have identified more than 28,000 megawatts of potential peak reduction from retail demand response programs.[38] This is more generation than currently exists in the entire state of Arizona.[39] Wholesale demand response programs can reduce another 26,000 megawatts.[40]

Integration of clean energy into the grid necessitates weather forecast models that minimize prediction errors and investment in resources to provide fast dispatch of electricity at times of grid variability.[41] Utilities and third-party companies can use energy storage units to provide ancillary services to the grid, including cost-competitive alternatives to investment in new power plants or transmission upgrades, but this market currently lacks clear regulatory standards within most states.

Renewable energy, energy storage, and energy-efficiency technologies all present substantial opportunities to utilities and states. Yet regulatory guidance is necessary to overcome challenges and realize these opportunities.

The role of PUCs in responding to challenges facing utilities

When Congress passed the Federal Power Act in 1935, it established a jurisdictional approach to sales of electricity that endures today. The Federal Energy Regulatory Commission regulates interstate transmission and wholesale sales of electricity. The individual states, typically acting through their public utility commissions, regulate the retail sales of electricity to consumers. At the retail level, the federal government's involvement in electricity sales has been mostly indirect, encouraging cleaner electricity generation through tax policy and promoting more efficient electricity use through standard setting for appliances or economic incentives.

Thus, state PUCs will play a critical role in helping investor-owned utilities, or IOUs, manage the challenges described earlier in carrying out their regulatory responsibilities. IOUs, regulated by PUCs, serve 68 percent of Americans.[42] In order to protect consumers in a captive market from being charged excessive rates for energy, PUCs set rates for electric consumers designed to offer consumer protections, while allowing utilities to meet their revenue requirements and continue to make investments in their electric grids.[43] Over the past 40 years, as the PUCs have considered regulatory standards and rate structures, Congress has periodically called for consideration of certain forward-looking policies. The Public Utility Regulatory Policies Act offers one tool for tackling these challenges by providing an accepted path for Congress to help set the agenda at the state level.

1978 Public Utility Regulatory Poliies Act[44]

In 1978, Congress passed PURPA as part of a broader set of federal reforms under the National Energy Act and in response to the 1973 oil crisis.[45] PURPA sought to encourage energy efficiency and development of renewable energy sources to increase U.S. energy security and access to low-cost energy. At the time, utilities employed promotional rate structures, which reduced prices per kilowatt as consumers increased their electricity usage. This contributed to an exponential

growth in American energy consumption at a time when energy supplies could not keep up with demand.[46] PURPA required PUCs to consider developing new rate structures and to implement new ratemaking methods that would increase energy efficiency while protecting consumer rates:

> *SEC. 111. (a) CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title.*[47]

PURPA established six policy standards for the PUCs to consider: Cost-of-service rates; declining block rates; time-of-day rates; seasonal rates; interruptible rates; and load-management techniques. These standards eliminated promotional rate structures that reduced the cost of electricity as customers increased their consumption and were designed to ensure that utilities offered rates that incentivized energy-efficiency investments while reflecting the price variability of wholesale electricity. Each of these reforms was adopted in the first three years of the act by at least 32 states, demonstrating the usefulness of PURPA as a tool for Congress to "effectively influence state ratemaking practices without forcing them to adopt any particular standard."[48]

PURPA ensured state compliance by obligating state regulatory agencies to "commence the consideration" no later than two years after PURPA's enactment and to make a determination on the standards no later than three years after enactment.[49] If a state regulatory agency refused to comply within three years, the act required consideration of the standards in the first rate proceeding following this timeframe.[50] This meant that each state PUC was obligated to open a formal process for consideration of adoption of the PURPA standards. If adopted, the PUC would require all IOUs in its service area to comply with the standards.

1992 Energy Policy Act PURPA amendment[51]

Following the first Gulf War of 1990 to 1991, energy efficiency again became a priority for Congress, motivated by concerns of U.S. dependence on foreign oil and a desire to reduce energy waste.[52] Four standards were added to PURPA in the Energy Policy Act of 1992. The act amended PURPA to add "integrated resource planning," "investments in conservation and demand management,"

and "energy efficiency investments in power generation and supply" to the list of standards that PUCs were obligated to consider.[53] Integrated resource planning, or IRP, is a process for utilities to evaluate electric supply and projected demand on an ongoing basis to ensure that they are providing electric services at a cost that services the interests of all stakeholders, including consumers and investors. IRP requirements grew out of demand-management programs implemented across the United States during the 1980s. By 1991, 14 states had adopted full IRP requirements, with another 18 states incorporating some IRP requirements as well.[54] State regulatory support for IRP and demand-management programs drove significant energy-efficiency investments, which more than doubled from $1.2 billion in 1990 to $2.8 billion in 1993.[55]

2005 Energy Policy Act PURPA amendments[56]

Congress next amended PURPA as part of the Energy Policy Act of 2005. As part of the law, Congress added five new standards to PURPA to promote energy efficiency and development of distributed electricity generation.[57] The amendment required state PUCs to consider standards for utilities to make net metering available to consumers (see below); diversify their fuel sources; develop a 10-year plan to increase generation efficiency; consider the deployment of smart meters that track electricity consumption on an ongoing basis; and provide interconnection of distributed electricity generation to homeowners when requested. The interconnection requirement had significant implications for today's electricity markets, since the vast majority of rooftop solar systems are dependent on interconnection to the grid.[58]

In the three years following the passage of the law, Arizona, North Dakota, Minnesota, Vermont, Ohio, and Texas all adopted portions of the standards or implemented modified versions of the new policies. Many states already had net metering laws in place—including Delaware, New York, Georgia, and Indiana—and declined to adopt the standards. Other states, such as Wyoming, declined adoption of the standards outright, determining that implementation would result in a sufficiently high burden on ratepayers.[59]

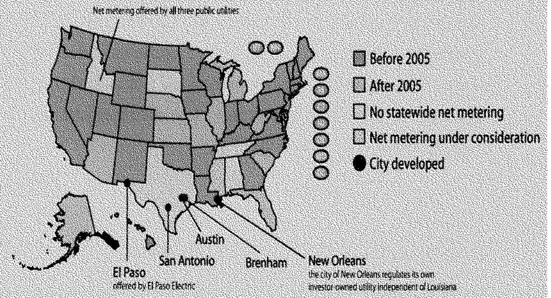
Net metering in the Energy Policy Act of 2005

Net metering is the policy that allows consumers who generate their own electricity to feed electricity they do not use back into the grid to offset their electricity consumption. Many states, or portions of states, allowed net metering by the early 2000s. After the passage of the Energy Policy Act of 2005, which amended PURPA to require consideration of net metering policies, 10 additional states adopted statewide net metering policies.[60]

FIGURE 1

State net metering programs

U.S. net metering programs enacted before and after the 2005 Energy Policy Act



Source: Database of State Incentives for Renewables & Efficiency, "Programs," available at http://programs.dsireusa.org/system/program (last accessed May 2015).

2007 Energy Independence and Security Act PURPA amendments[61]

Two years after the passage of the Energy Policy Act of 2005, Congress passed the Energy Security and Independence Act of 2007, or EISA, which included two amendments to PURPA to expand integrated resource planning and incentivize energy efficiency through rate design modifications. If adopted, integrated resource planning standards obligated utilities to include cost-effective energy efficiency as an investment priority. Rate design modification, or decoupling, encouraged utilities to develop and propose electric rates that would allow them to remain profitable while also providing customers with energy-efficiency savings, reducing the total electric consumption of their customers. The EISA also included two additional standards on smart-grid investments for PUCs to require utilities to consider smart-grid investments before undertaking nonadvanced grid investments and to provide information to customers on electricity usage as recorded by smart meters. These amendments also indicated policies and best practices that states could adopt that would incentivize utilities to deploy smart-grid technology and energy-efficiency investments.[62]

The PUCs of Idaho, Kentucky,[63] Rhode Island, South Dakota,[64] Utah, and Wyoming all conducted review of the advanced-metering and demand-pricing provisions in the EISA. The Kentucky and South Dakota PUCs implemented the provisions. Wyoming and Utah decided not to adopt the provisions. Idaho and Rhode Island determined that their existing standards satisfied the EISA or were being considered in separate cases.[65] PUCs in California, Connecticut, Delaware, Minnesota, New York, North Carolina, South Carolina, Tennessee, Utah, and Washington all determined that the laws and regulations in place before the passage of the EISA satisfied the new provisions and took no further action. The state legislatures of Colorado and Maine passed legislation to require their PUCs to implement policies in line with the EISA.[66]

Table 1
Established PURPA standards for electric utilities

Standards that Congress directed PUCs to consider

Federal standards	Description of standards	Deadline for PUC consideration
	1978 PURPA	
1 Cost of service	Directs electric utilities to reflect to the best of their ability the cost of providing electricity in customer electric rates	Must consider two to three years after passage
2 Declining block rates	Prohibits the use of declining block rates, in which the price of electricity decreases as electric consumption increases—unless the cost of providing electricity over this period also decreases	Must consider two to three years after passage
3 Time-of-day rates	Directs electric utilities to charge electric rates on a time-of-day basis to reflect price variability throughout the day	Must consider two to three years after passage
4 Seasonal rates	Directs electric utilities to charge electric rates on a seasonal basis to reflect price variability throughout the year	Must consider two to three years after passage
5 Interruptible rates	Directs electric utilities to offer interruptible rates to commercial and industrial electric customers—rate agreements in which customers agree to reduce their electric consumption at times of peak demand in exchange for better rates	Must consider two to three years after passage
6 Load management techniques	Directs electric utilities to offer load management techniques to help customers reduce peak demand and increase electric reliability	Must consider two to three years after passage
	1992 Comprehensive National Energy Policy Act	
7 Integrated resource planning	Directs electric utilities to employ integrated resource planning and to report electric load and resource cost projections over a specific period of time to invest in the mix of electric resources that costs the least, including investments in energy efficiency	Must consider two to three years after passage; secretary of energy directed to report on progress after two years
8 Conservation and demand management	Sets a standard for electric rates to ensure that electric utility investments in energy efficiency are recoverable through electric rates and as profitable as investments in new electric infrastructure	Must consider two to three years after passage; secretary of energy directed to report on progress after two years

Federal standards	Description of standards	Deadline for PUC consideration
9 Energy-efficiency investments	Directs state regulators to encourage electric utility investment in energy efficiency and to consider replacing policies that disincentivize energy efficiency with policies to encourage new investment and best practices	Must consider two to three years after passage; secretary of energy directed to report on progress after two years
10 Consideration of the effects of wholesale power purchases on utility cost of capital	Directs state PUCs to evaluate whether electric utility purchases of long-term wholesale power supplies, instead of utility investment in new generation, hold the potential for increases or decreases in utility costs of capital and associated retail electric rates	Must consider two to three years after passage
	2005 Energy Policy Act	
11 Net metering	Directs electric utilities to provide net metering services to the utility's electric customers upon request for onsite electricity generation	Must consider two to three years after passage
12 Fuel sources	Directs electric utilities to develop plans to minimize dependence on a single fuel source and to diversify their use of fuels and generating technologies, including renewable energy	Must consider two to three years after passage
13 Fossil-fuel generation efficiency	Directs electric utilities to develop and implement 10-year plans to increase efficiency of fossil-fuel electricity generation	Must consider two to three years after passage
14 Time-based metering and communications (smart metering)	Instructs PUCs to consider whether electric utilities must provide smart meters to customers to facilitate the requirement that utilities offer time-based electric rates to customers that reflect varying wholesale electric costs throughout the day	Must consider two to three years after passage
15 Interconnection	Directs electric utilities to provide interconnection for onsite generating facilities to any electric customer that the utility serves, allowing customers to install distributed generation on their property	Must consider one to two years after passage
	2007 Energy Independence and Security Act	
16 Integrated resource planning	Directs electric utilities to integrate energy efficiency into utility, state, and regional plans and to adopt policies that make cost-effective energy efficiency a priority	Must consider two to three years after passage
17 Rate design modifications to promote energy-efficiency investments	Directs electric utilities to offer electric rates that incentivise energy efficiency investments and to offer programs to ratepayers to increase energy efficiency; directs PUCs to consider providing utilities incentives for energy-efficiency programs and to consider supporting residential energy-efficiency programs	Must consider one to two years after passage
18 Consideration of smart-grid investments	Directs electric utilities to consider smart-grid investments before undertaking nonadvanced grid investments; directs PUCs to allow electric utilities to recover the costs of smart-grid investments and equipment replacements for equipment rendered obsolete by smart-grid investments	Must consider one to two years after passage
19 Smart-grid information	Directs electric utilities to provide information to customers on smart-meter recorded usage and electric price variance over time when requested and online; directs utilities to provide information on sources of electric generation to customers, including associated greenhouse gas emissions where available.	Must consider two to three years after passage

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2009 American Recovery and Reinvestment Act State Energy Program

In an effort to build on energy efficiency at the state level, the American Recovery and Reinvestment Act of 2009, or ARRA, appropriated $3.1 billion for the federal State Energy Program, or SEP.[67] Under this program, the Department of Energy provides funding to states for increasing energy efficiency, reducing energy imports, increasing electric reliability, and reducing the environmental impacts of energy production and use.[68]

ARRA required as a condition of receiving SEP funding that the governors assure the secretary of energy that the appropriate regulatory authority for each gas and electric utility would seek to implement a policy that encourages the alignment of utility incentives and efficiency goals. The DOE received letters of assurance from all U.S. governors by the end of August 2009, though many of the letters lacked specific explanations of how states would promote the policies of ARRA 410(1).[69]

The ARRA provision achieved some success in persuading certain states to encourage energy efficiency by adopting electric-rate decoupling or lost-revenue adjustment mechanisms, which can reduce disincentives for utility investment in energy efficiency. Alabama, Arizona, Arkansas,[70] Colorado, Indiana, Kansas, Louisiana,[71] Missouri, Mississippi,[72] New Jersey, Rhode Island, South Dakota, Washington, and Wyoming each implemented a decoupling program between 2009 and 2013.[73] California also established a PUC process to review grid modernization projects and investments by IOUs seeking ARRA funding.[74]

In Arizona, ARRA appeared to have a distinct role in persuading the Arizona Corporation Commission, or ACC, to adopt a rate decoupling plan. In 2010, the ACC wrote that: "ARRA has asked participating states to consider general policies that ensure that utility financial incentives are aligned with helping customers use energy efficiency. Arizona, in accepting ARRA funding, agreed to analyze and consider these policies."[75] The ACC worked with Arizona's utilities, consumer groups, and other stakeholders to produce a proposal that would allow utilities to file a rate decoupling proposal in December 2010.[76] Since 2011, the ACC has approved revenue decoupling for the Arizona Public Service Company and Tucson Electric Power.[77]

However, ARRA did not achieve all of its desired goals because the conditions for receiving SEP funding only required state governors to "obtain necessary assurances" from commissioners that they would seek to implement "a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently."[78] Unlike the consideration requirements in PURPA, the ARRA provision lacked enforcement capabilities and was difficult to monitor, due to the vague nature of the requirement. The number of states whose governors offered assurances of action without providing specific commitments or proof of the existence of apparent outcomes suggests that the lack of stronger language failed to compel state leaders or their PUCs to consider fully the application of new energy policies. In contrast, the standards laid out in PURPA were supported by a clear requirement that each PUC open formal proceedings to consider whether to implement the standards within a three-year timeframe.

Clean energy solutions for PUCs to consider

While much has changed in the U.S. energy sector since 1978, the Public Utility Regulatory Policies Act has repeatedly proven itself as a modest but useful tool for Congress to encourage smart standards for utilities at the state level. Throughout the country, including in states that initially declined to adopt the standards that PURPA established in 1978, electric rates offered by investor-owned utilities to encourage energy efficiency and net metering services are commonplace. Ninety percent of states have net metering policies in place, and 72 percent of states have adopted some form of energy-efficiency ratemaking standard.[79] Energy consumption no longer grows at the same pace as the overall economy,[80] and renewable energy is becoming cost competitive with fossil fuels.[81]

Given the success that Congress has had in using PURPA to spur productive state action historically, Congress should now consider amending PURPA once again to bring focus to today's challenges and opportunities in the electricity sector. In the face of climate change and evolving electricity markets, it is vital that public utility commissions work with utilities to encourage investments in resilient systems and to consider long-term plans to incorporate increasing amounts of clean energy generation and storage in their state grids. Congress can amend PURPA to support these initiatives and help states increase their energy security and electric reliability, as well as support electric-rate stability over the long term.

Congress should amend PURPA to require the PUCs to consider three important policies:

- Boost energy-efficiency efforts through technology and regulation.
- Establish policies to encourage utilities to use clean energy to reduce pollution.
- Ensure utilities will have the resilience to function reliably in the future.

Energy-efficiency incentives and affordability

First, Congress should require PUCs to consider implementing the policies that state governors already committed to pursue on a bipartisan basis in 2009. Congress appropriated State Energy Program funding in ARRA on the condition that state governors and PUC commissioners offer assurances that they would pursue policies that would ensure that utility financial incentives are aligned with helping their customers use energy more efficiently. The rate structures should balance timely cost recovery and a timely earnings opportunity for utilities with cost-effective measureable and verifiable efficiency savings in a way that sustains or enhances utility customers' incentives to use energy more efficiently.

PUCs should consider regulatory incentives to make energy-efficiency investments as a means to avoid future investment by IOUs in new generation and transmission infrastructure. Energy-efficiency programs can obviate the need for new transmission and distribution assets and reduce energy demand at one-third of the cost of new generation on a per-kilowatt basis.[82] Because these benefits may not be realized under existing rate structures, regulators should work with the Department of Energy to develop new techniques to validate and value energy-efficiency savings and avoided costs of infrastructure investment. Shifting these investment incentives may require changes to existing rate structures, but they can provide consumers and the grid with numerous increased benefits.

Integrating clean energy and energy storage into the grid

Second, Congress should require PUCs to consider how to encourage integration of clean energy and energy storage into their grid. As the cost of clean energy technology continues to fall, regulators must be proactive in establishing standards for deployment that achieve economic, environmental, and other societal benefits and that address any institutional biases against generation. Clean energy sources are nonpolluting, so they do not impose health risks on the communities they serve; can be placed closer to demand centers, mitigating the need for additional investment in transmission; and with the use of microgrids that can operate independently of the traditional electric grid, can provide access to electricity during blackouts.

Clear regulatory guidance from state public utility commissioners can send strong signals to energy markets by eliminating barriers for integration of renewable energy, encouraging investment in energy storage to balance loads from intermittent sources of energy, and examining what policies can facilitate the use of fossil-power generation that captures and stores carbon pollution. Regulators that consider the value offered by clean energy beyond the immediate benefits can better serve state consumers with what the DOE calls a "portfolio of electricity options that meet their state specific goals for reliable, affordable, and clean electricity."[83] As inexpensive sources of renewable electricity make up an increasing share of state electricity generation, regulators also will have to adopt better planning and prediction methods to accommodate clean energy in a way that ensures grid stability and reliability. In states that have not already established net metering and interconnection standards, PUCs should consider their applications.

Regulatory guidance also has been cited as one of the primary tools to enable proliferation in the energy storage market—both large-scale and distributed storage.[84] PUCs that embrace a proactive approach to the benefits conferred by energy storage can work with utilities in their states to direct investments into energy storage systems that reduce the need for new investment in peaking plants; transmission and distribution upgrades or new transmission to relieve grid congestion; and load-management infrastructure. Specifically, regulators could consider rate structures that value ancillary services and demand-response support of energy storage appropriately or whether energy storage is most appropriately classified as a distribution asset or a storage asset, which would offer clarification to utilities and investors on the value of energy storage investments.[85] Similarly, regulators could consider the eligibility of third-party providers to aggregate energy storage services at the distribution level to provide their collective ancillary benefits, such as load moderation to increase grid stability. Energy storage offers benefits at both levels of the electric grid, but because regulators treat generation assets and distribution assets differently, clarification of this can provide stronger market signals than currently exist.[86]

Building resilience into utilities

Third, Congress should require PUCs to consider how to encourage utility resilience planning to protect investments against extreme weather and drought in a changing climate. Shifting weather patterns will require utilities to invest in resources to harden infrastructure, conserve water, and increase the resilience of their assets. Planning and proactive investment by IOUs can protect their ratepayers and investors from excessive recovery costs and falling operational efficiencies

due to climate change. Regulators could encourage their utilities to develop long-term plans for their facilities that determine acceptable levels of risk to climate change, particularly during rate cases to evaluate investments in new assets. Such planning will support grid reliability and long-term affordability.

One new rate structure that could encourage utility investments in resilience and reliability is performance-based ratemaking, or PBR. Under a PBR regulatory structure, a PUC sets performance goals over a set timeframe that utilities must comply with, such as reliability, efficiency, or affordability. The better a utility's performance against these benchmarks, the more revenue the utility is entitled to receive. Conversely, if a utility does not achieve the benchmarks, a penalty is incurred.[87] In 2012, the Maryland Grid Resiliency Task Force recommended implementing a PBR structure to align customer and utility incentives for reliability,[88] and in 2014, the Maryland Public Service Commission conducted an evaluation into the application of PBR.[89] This approach could be used to ensure that utilities are increasing resilience over time.

Conclusion

The nation's electricity sector is undergoing historic change with the opportunity for tremendous benefits, from cutting pollution to upgrading and strengthening the grid. To most easily realize these benefits, however, the state public utility commissions should take a forward-looking approach and act to encourage clean energy, boost energy efficiency, and build resilience in their electric utility systems. To facilitate this forward-looking approach at the state level, Congress should amend PURPA to call upon the states to undertake formal consideration of these important and timely issues.

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Senator CANTWELL. I want to make mention of the fact that FERC is investigating price spikes in the California ISO Energy Wholesale Market. And the notion that the California ISOs are the "Holy Grail" for the Pacific Northwest is one that I will always have more to say about that. And I will always fight for cheap hydropower.

Again, I appreciate the testimony of the witnesses here.

Mr. Hunter described the energy sector with a workforce that is retiring at a rate higher than 50 percent; so it's clear we need to focus on this.

Ms. Ericson knows that there are many models here on how to generate this workforce that she is looking at and some of the things that she has done with Alstom. I hope that we will incorporate all of that into how we move forward on preparing for what the Secretary in the Quadrennial Energy Review said will be a huge demand and need for skilled workers in these areas. This presents an exciting opportunity for many in the United States of America.

I think we have to figure out how to target these programs and get them right, and make sure that we meet the ever-increasing economic opportunity with the skill that will be required.

I look forward to working with you on all of that, and I very much appreciate the testimony from our witnesses today.

The CHAIRMAN. Thank you, Senator Cantwell, and thank you again to each of our witnesses. We appreciate your comments. If members have additional questions they might want to have you respond to, we would hope that you would give us that time as well. Again, thank you very much and we stand adjourned.

[Whereupon, at 11:57 a.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. Senate Committee on Energy and Natural Resources
May 14, 2015 Hearing: Energy Infrastructure Legislation
Questions for the Record Submitted to Ms. Erica Bowman

Questions from Chairman Lisa Murkowski

Ms. Erica Bowman

Question 1: Regarding S. 1228, the North American Energy Infrastructure Act, does limiting the focus to certificates of crossing mitigate the possibility of a long, drawn-out, litigious NEPA process?

Thank you for your question, Chairman Murkowski.

It is our understanding that S. 1228, The North American Energy Infrastructure Act (the "Act"), seeks to remove the burdensome and unnecessary requirement that a Presidential Permit be approved for a cross-border segment of an oil or natural gas pipeline or electric transmission facility located at the national boundaries of the U.S. with our neighbors Canada and Mexico. The Act would also institute greater certainty into the permitting process by requiring the relevant official to act within 120 days after final NEPA action is taken. ANGA supports this legislation. The Act provides for a common sense permitting process for critical infrastructure projects across North American borders while maintaining a robust review process that will enhance energy networks with our neighbors.

We strongly support the legislation. Nevertheless, we believe that the potential for a drawn-out NEPA process and accompanying litigation would remain. The Act would provide greater certainty by requiring the relevant official to issue a "certificate of crossing" following final action under the NEPA process (see Section 4(b)(1)). Although helpful, the Act does not seek to amend or streamline the NEPA process for infrastructure projects with cross-border segments.

In general, the permitting process for any given natural gas pipeline project is complex and involves permitting with numerous federal, state and local agencies as well as stakeholder engagement at all levels. Earlier this month while testifying before the House Energy & Power Subcommittee on natural gas pipeline infrastructure, the President of the Interstate Natural gas Association of America (INGAA) stated that "...recent experience suggests that it typically takes about four years for an interstate natural gas pipeline to advance from concept to operation."[1] In 2013, the GAO examined major natural gas pipeline projects and, when considering interstate pipelines, found that the average processing time from pre-filing to certification for interstate natural gas pipeline projects was 558 days, and the processing times ranged from 370 to 886

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[1] Testimony of Donald F. Santa, President and Chief Executive Officer of the Interstate Natural Gas Association of America, before the Subcommittee on Energy and Power, Committee on Energy & Commerce, U.S. House of Representatives. May 13, 2015 @ page 6.

days."[2]

Question 2: Regarding S. 1242, the Regional Gas Consumer Protection Act, does FERC already have the discretionary authority to take regional considerations into account? Is legislation in this area needed?

As a preliminary issue, although it is not an enumerated authority under the jurisdiction of FERC and because DOE is the agency charged with making the public interest determination under Section 3 of the Natural Gas Act, the relevant scope of authority to be examined is that of DOE. Today, FERC's role in the Section 3 approval process primarily consists of the NEPA review (which actually does include an economic analysis).[3,4] *The DOE retains authority over the remainder of the public interest analysis and the decision to authorize imports or exports.*[5]

In practice, DOE generally relies on recent EIA and NERA studies on the effects of gas exports on domestic and international markets for its economic analysis. DOE may also look at studies submitted by project proponents, which may touch on regional impacts. In its conditional approval of the Dominion Cove Point project, for instance, DOE looked at a DCP-submitted study addressing forecasted export-driven changes to Dominion South Point gas prices in addition to Henry Hub prices.[6] *DOE also examined other types of regional considerations (e.g., environmental, employment, tax revenue) raised by intervenors and commenters. DOE currently has the discretion to look at regional gas supply and has chosen to do so in recent analyses.*[7]

Given the FERC economic analysis, DOE's economic analysis and the DOE's discretionary authority to consider regional analyses, we believe S. 1242 is unnecessary. Furthermore, we do not believe that a mandatory regional analysis would be helpful in providing decision makers with information that would sway a public interest determination in one direction over another. The reason for this is largely that "supply" is no longer an

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[2] U.S. Government Accountability Office. "Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Process Include Multiple Steps, and Time Frames Vary." GAO Report -13-221. February 2013. Pg. 26.
[3] NGA § 3 refers to "the Commission" having authority over export approvals; but the Commission is defined in the NGA as the Federal Power Commission (FPC), not FERC (this language is left over from the original 1938 version of the Act). The FPC was dissolved in 1977 and FERC was established, taking over much of its role. Nevertheless, FERC did not inherit the FPC's authority over gas imports and exports under Section 3. The Department of Energy Organization Act of 1977 § 402(f) put gas imports and exports under the jurisdiction of the DOE except to the extent that DOE chooses to delegate part of that authority to FERC. So, the upshot is that where NGA § 3 says "Commission," by default it's actually referring to DOE, not FERC. In 1984, DOE delegated some of its § 3 approval authority to FERC, but only as to siting, construction, and operation of LNG terminals. See 49 Fed. Reg. 6684, 6690 (Feb. 22, 1984) ["1984 Policy Guidelines"] (essentially the approvals required by § 3(e)).
[4] FERC, "Pre-Filing Environmental Review Process," accessed May 22, 2015, https://www.ferc.gov/help/processes/flow/lng-1-text-.asp.
[5] The bill's reference to "the Commission" should probably be read as referring to DOE, and the references to FERC in the preamble would be somewhat incongruous. Amending subsection (e), which actually does cover areas delegated to FERC is interesting because economic analysis is generally carried out by DOE as part of the Subsection (a) public interest analysis.
[6] See DOE Order No. 3331.
[7] FERC, "Pre-Filing Environmental Review Process," accessed May 22, 2015, https://www.ferc.gov/help/processes/flow/lng-1-text-.asp.

issue for any region of the United States. As I noted in my written statement before the Committee, U.S. natural gas consumption in 2014 totaled 27 trillion cubic feet (Tcf) while the total volume of U.S. natural gas recoverable with existing technology is more than 100 times greater – over 2,850 Tcf. Even when taking into account expected increases in natural gas consumption across the power, industrial, and exports sectors, EIA projects increased production and stable prices.[8] *In other words, we have enough natural gas to use more domestically in all regions of the country and to send it abroad to our allies and trading partners.*

S. 1242 may not only slow or reduce LNG exports, but may also slow the expansion of much needed regional infrastructure that would help to alleviate the high winter natural gas prices in the Northeast by discouraging "alternative anchoring" facilities. As explained in my written testimony, the combination of increased natural gas use by electric generators and electric market rules that do not allow for appropriate firm cost recovery for electric generators has led to infrastructure constraints during high demand periods. Electric generators are experiencing difficulty in trying to recover the costs of firm natural gas contract costs making it difficult for them to act as anchoring facilities on a pipeline. Alternative anchoring facilities (such as LNG export facilities) can store gas for use during high demand periods, should be welcomed into the region. In many cases these proposed LNG export facilities will support additional infrastructure by contracting for firm pipeline capacity and will have the flexibility to release natural gas bi-directionally, either as an exporter of LNG or as a supplier into the region through LNG regasification.[9]

In conclusion, we do not believe that S. 1242 is necessary legislation. Supply is not the issue and denying or delaying LNG exports because of a region's unrelated challenges will not resolve the underlying problems of a need for additional infrastructure and modernization of market rules for power generators.

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[8] U.S. EIA. 2015 Annual Energy Outlook.
[9] Downeast LNG, "Downeast LNG Moving Forward with Plans for LNG Import/Export Terminal," June 2014, accessed May 26, 2015, http://www.downeastlng.com/pressrelease.php?id=54.

U.S. Senate Committee on Energy and Natural Resources
May 14, 2015 Hearing: Energy Infrastructure Legislation
Questions for the Record Submitted to Ms. Erica Bowman

Questions from Senator Wyden

Ms. Erica Bowman

Questions: I know that demand response has proven to be a valuable tool in electricity markets, and am interested to know if demand response could also work for natural gas. What is your assessment of the potential for demand response in natural gas? What are the hurdles to moving forward with developments in this area? What actions could be taken to help to unlock this potential?

Thank you for your question, Senator Wyden.

The natural gas sector already has a strong demand response program that operates largely through consumer contracting choices. Interstate pipelines and/or the local distribution companies (LDCs) offer consumers the choice of firm transportation/delivery or interruptible transportation/delivery services. Infrastructure capacity for both interstate pipelines and LDCs is sized to meet the demand of firm customers. In other words, firm customers are ratepayers who pay a FERC-authorized cost of service rate to ensure deliverability under all circumstances, except during force majeure events.[1] On the other hand, customers who choose to contract for interruptible service are stating up front that they are willing to incur service interruptions during high demand events. This is demand response in the natural gas sector.

Unlike the electricity sector where both planning reserve margins[2] and system redundancies are required to serve electricity customers, the natural gas industry builds its system to serve firm customers during extreme events and releases unused transportation/delivery capacity to interruptible customers throughout the year. In the

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[1] Levitan & Associates, Inc, "Gas-Electric Interface Study: Existing Natural Gas-Electric System Interfaces," February 2014, 11.

[2] The North American Electric Reliability Corporation (NERC) states that,

> "Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand during a planning horizon.
>
> Planning Reserve Margin equals the difference in Deliverable or Prospective Resources and Net Internal Demand, divided by Net Internal Demand. Deliverable Resources are calculated by the sum of Existing, Certain and Future, Planned Capacity Resources plus Net Firm Transactions. Prospective Resources include Deliverable Resources and Existing, Other Resources. Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load."

For most electric regions in the United States, this planning reserve margin is 15%.

See http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx for more detail.

electric sector, demand response programs originated to help electricity system planners identify "interruptible" capacity. In the natural gas sector, the "interruptible" capacity already exists because customers identified up front that they are "interruptible". Therefore, electric sector demand response type programs are not as applicable to the natural gas sector.

Furthermore, infrastructure investment coupled with limited natural gas infrastructure cost recovery mechanisms in the Northeast's electricity markets has led to constrained natural gas infrastructure during high natural gas demand periods. This scenario has led to high prices for consumers and limited economic growth in the region. Given this, it is imperative for the Northeast and other regions looking to expand use of natural gas as a fuel supply to support additional pipeline capacity. Permitting timetables that provide for appropriate public input without unreasonable delay are critical to ensuring infrastructure is expanded thereby enabling deliverability capability and flexibility.

U.S. Senate Committee on Energy and Natural Resources
May 14, 2015 Hearing: Energy Infrastructure Legislation
Questions for the Record Submitted to Mr. Jonathan M. Weisgall

Questions from Chairman Lisa Murkowski

Question 1: *Redundancy and inconsistency clutter the permitting process – divergent interpretations of rules across different field offices of the same agencies, duplicative assessments at the state and federal level, the ability of one office or agency to significantly delay and entire permitting application. What can Congress do to bring some reasonableness and certainty to this byzantine process? Can my legislation, S. 1217, the Electric Transmission Infrastructure Permitting Improvement Act, be further strengthened?*

Response to Question 1: We urge the Committee to focus on substantially improving the overall quality and timeliness of the existing federal permitting process for electric transmission and natural gas pipeline infrastructure on federal lands as it puts together an energy bill. With respect to electric transmission, we recommend strengthening S. 1217, Section 2 (b) (1) from "to improve the timeliness and efficiency of electric transmission infrastructure permitting" to actually include a specific timeframe. Our written testimony suggests 3-4 years, which we view as reasonable/achievable. A January 2013 General Accounting Office study suggests review times could be reduced to 1.5 years with appropriate pre-application meetings.[1]

The other area we suggest strengthening in S. 1217 is to provide the Federal Energy Regulatory Commission (FERC) "Transmission Ombudsperson" established under the bill with authority to resolve interagency conflicts, set and enforce deadlines applicable to the other agencies participating in the review of a particular project, and require that any extension requests be approved first by the Secretary who has jurisdiction over the requesting agency. For example, there are instances where the Department of Defense has rejected proposed transmission routes meant to avoid endangered species habitat or to avoid more expensive undergrounding because the routes would be located near military training grounds. Our PacifiCorp utility's Boardman-to-Hemingway[2] and Vantage-to-Pomona[3] transmission projects are having difficulty finalizing their routes through the Rapid Response Team on Transmission or the Pacific North West Renewable Infrastructure Team because of competing federal agency interests. Experience tells us that unless there is interagency consensus, the authorized officer will not make a decision and projects will linger.

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[1] See, http://www.gao.gov/products/GAO-13-189

[2] See, http://www.boardmantohemingway.com/

[3] See, http://www.pacificorp.com/tran/tp/vtph.html

<u>Question 2</u>: *In your testimony, you note problems utilities have had with PURPA "gaming" created by FERC's "one-mile" rule where larger projects are divided into smaller QF projects in order to capture higher PURPA prices under the mandatory purchase obligation. Please explain more fully.*

<u>Response to Question 2</u>: FERC currently has a "one-mile" rule for determining the size of a qualifying facility (QF) project, meaning that all QFs by the same owner using the same resource located within one mile are considered a single QF project. However, it is relatively easy for a QF developer to group wind turbines or solar photovoltaic (PV) arrays into separate corporate entities and locate them just beyond one mile from each other for the purpose of qualifying for the small power producer mandatory purchase obligation under the Public Utility Regulatory Policies Act (PURPA).

Contrary to Congress' intent in passing PURPA, increasingly there is evidence that QF developers are deliberately structuring their projects for the sole purpose of qualifying as a small power producer under PURPA (maximum size of 20 megawatts (MW) in those areas where competitive markets exist; maximum size of 80 MW outside these areas).

For example, Berkshire Hathaway Energy's PacifiCorp utility has seen many QF developers across its six-state service area disaggregate large QF projects into smaller ones to take advantage of the PURPA mandatory purchase obligation as well as higher standard offer prices (awarded for smaller projects). PacifiCorp has most prominently experienced this type of gaming activity with wind and solar PV QF developers. A significant driver to this disaggregation activity is the ability of multiple QF projects, being pursued by the same developer, to share a common interconnection point with the utility's electrical system. In these circumstances each QF project, set one mile apart, will typically have a small collection substation and billing meter. Power from each QF project is metered and delivered via a feeder line to the main interconnection feeder, which then delivers to the interconnection substation deemed the point of delivery. Losses and station service are measured between the main point of delivery and each project meter and then allocated to the QF projects. This activity provides a cost benefit to the QF developer because interconnection costs can be spread across multiple projects versus a single project.

Examples of disaggregation of large renewable projects into smaller projects:

- *<u>Idaho</u>*. Prior to applying for a QF contract, one developer, Cedar Creek Wind LLC, a company jointly owned by Western Energy and Summit Power Group, had submitted a bid into PacifiCorp's 2008/2009 renewable request for proposal (RFP) process as a single 151-MW wind project to be located in Bingham County, Idaho. PacifiCorp did not select the project through its RFP process because the offered price was too high and not competitive with other alternatives. In March 2010, the same developer requested QF pricing for two 78-MW projects, but the avoided cost rate offered at the time was too low. In May 2010, in an attempt to secure a more favorable standard rate, the developer reconfigured the project again, this time as five distinct projects, totaling 133 MW, all while still meeting FERC's one-mile rule.

- Steep Ridge (25.2 MW)
- Rattlesnake Canyon (27.6 MW)
- North Point Wind LLC (27.6 MW)
- Fine Pine Wind LLC (25.2 MW)
- Coyote Hill (27.6 MW)

• *Oregon*. The Oregon Windfarm QF project located in eastern Oregon is a large 64.5-MW wind project that was disaggregated by the developer, John Deere Renewables, into nine QF projects ranging in size from 1.65 MW to 10 MW and constructed in 2008.[4]

  - Echo Big Top Wind Farm (1.65 MW)
  - Echo Butter Creek Power (4.95 MW)
  - Echo Four Corners Wind Farm (10 MW)
  - Echo Four Mile Canyon (10 MW)
  - Echo Oregon Trail Wind Farm (9.9 MW)
  - Echo Pacific Canyon Wind Farm (8.25 MW)
  - Echo Sand Ranch (9.9 MW)
  - Echo Wagon Trail (3.3 MW)
  - Echo Ward Butte Wind Farm (6.6 MW)

  The projects were not independent family or community-based projects and clearly were a disaggregation of a large single wind project. The nine wind projects are operated today as a single wind project, delivering electricity to a single interconnection point on PacifiCorp's system, and are currently owned and managed by Exelon Generation, which acquired John Deere Renewables in 2010.

• *Utah*. As of May 1, 2015, PacifiCorp has executed several large (50 MW to 80 MW) solar PV QF contracts in Utah where the developer secured a large generator interconnection agreement over 80 MW and then developed multiple adjacent large QF projects that feed into that interconnection agreement. For example, SunEdison has three 80-MW projects called Escalante I, II and III all adjacent to each other, technically meeting FERC's one-mile rule, but they are managed as a single project. In an earlier example of disaggregation, SunEdison and First Wind (later acquired by SunEdison) executed seventeen 3-MW standard offer solar PV QF contracts in 2013 and 2014. Several of these projects are built on a single land parcel, use a common interconnection point of delivery, and are constructed to meet the one-mile PURPA rule.

• *Wyoming*. Currently, EverPower Wind Holdings is developing the Mud Springs Wind Ranch Project and requesting three 80-MW wind QF contracts for projects that are all adjacent to each other in Montana, again meeting FERC's one-mile rule, but sharing a common 230-kV transmission line they are building into PacifiCorp's service area

[4] See, http://www.rnp.org/project_map

near Frannie, Wyoming in order to secure Wyoming avoided cost prices. The three phases/projects will each be owned by a separate Limited Liability Company, but operated as a single large wind farm.

- Mud Springs Wind Ranch Pryor Caves Wind Project (80 MW)
- Mud Springs Wind Ranch Mud Springs Wind Project (80 MW)
- Mud Springs Wind Ranch Horse Thief Wind Project (80 MW)

Question 2a: *Has the Commission attempted to address this problem? If not, why not?*

Response to Question 2a: No, FERC has not attempted to address gaming of its one-mile rule. Unfortunately, FERC enforces its one-mile rule literally and has stated it will not examine whether larger projects have been divided into smaller projects in order to obtain QF status, so long as the projects comply with the one-mile rule.

FERC's one-mile rule is part of the rule that defines what a facility must do to achieve QF status. In order to qualify as a QF, a facility that is owned by the same persons and located at the same site may not exceed 80 MW.[5] The one-mile rule provides:

> "... facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought ..."[6]

FERC has stated the one-mile rule does not contain a "rebuttable presumption" that may be used by a utility to contest the QF status of a given project. In *Northern Laramie Range Alliance*, 139 FERC ¶61,190, at PP 12, 22 (June 8, 2012),[7] FERC rejected the argument that the one-mile rule contains a presumption that may be rebutted with evidence of gaming:

> "Contrary to the arguments of Petitioner... section 292.204(a)(2)(i) of the Commission's regulations was not intended to establish and did not establish merely a rebuttable presumption. Instead, section 292.204(a)(2)(i) established a rule that facilities that use the same energy resource, and that are owned by the same person(s) or its affiliates and that are located within one mile of each other are at the same site. There is certainly no language in that rule that suggests otherwise, i.e., that it is merely a rebuttable presumption. To the contrary, the language reads, as it was supposed to read, as a rule."

[5] 18 C.F.R. §292.204(a)(1).

[6] 18 C.F.R. §292.204(a)(2)(i).

[7] *See also DeWind Novus, LLC*, 139 FERC ¶61,201, at P25 (June 11, 2012) ("one-mile rule for determining whether small power generation facilities are 'at the same site' is a rule and not a rebuttable presumption").

Based on the Commission's interpretation of its one-mile rule, utilities lack the ability to show FERC that projects are engaged in gaming in order to obtain QF status.

Question 2b: *What is BHE's suggested legislative solution?*

Response to Question 2b: As demonstrated above, QF developers left unchecked can impose significant costs on utility customers by exceeding the statutory and regulatory size limitations.[8] To limit any one-mile gaming opportunities, Congress should instead adopt a rebuttable presumption that facilities located more than a mile apart are independent projects, but a utility or other interested party should have the right to rebut that presumption by showing that two or more facilities are part of a common enterprise. Such a PURPA modernization proposal would enable utilities to rebut FERC's assumption that QFs are independent for purposes of applying the 20- or 80-MW size limitations where the sites are located more than one mile apart by demonstrating that the facilities are part of a common enterprise.

Such an anti-gaming approach above mirrors the approach taken by FERC in Order No. 688, which stands in contrast to the rigid one-mile rule. There, FERC adopted several rebuttable presumptions with respect to nondiscriminatory access to the market based on the size of the QF. Unlike the one-mile rule, 18 C.F.R. §292.309(d)(1) contains an express rebuttable presumption that a QF with a capacity of 20 MW or less does not have nondiscriminatory access to the market. In interpreting this rule, FERC stated:

> "The Commission will not allow for gaming of this 20 MW rebuttable presumption. If parties are concerned that a QF has engaged in gaming with regard to the certification or siting of a particular facility, we encourage those parties to bring their concerns to our attention. In any such proceeding, we will consider all relevant factors, including, but not limited to, ownership, proximity of facilities, and whether facilities share a point of interconnection. For purposes of evaluating proximity of facilities with regard to alleged gaming of this rebuttable presumption, we will not be bound by the one-mile standard set forth in 18 C.F.R. §292.204(a)(2)."[9]

A rebuttable presumption mirrors the approach recommended by the Edison Electric Institute (EEI) to FERC in 2009 when the agency considered updating its small power production facility regulations in Docket No. RM09-23-000. In its comments on FERC's proposed rulemaking, EEI asked FERC to amend its QF regulations to provide for a rebuttable presumption that two or more QFs are independent for purposes of QF certification where the sites are located more than one mile apart. As EEI explained, this presumption could be overcome upon a demonstration showing that two or more facilities that are more than one mile apart are part of a "common enterprise."

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[8] PacifiCorp reports that over the next 10 years it is under contract to purchase from QFs at an average price that is 43% higher than current market prices.

[9] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, at P 77 (October 20, 2006).

Factors that may be considered part of a "common enterprise" for purposes of rebutting the presumption would include: (1) whether the facilities have at least one common or affiliated owner or developer; (2) whether the owner or developer has treated the facilities as a single project for purposes of other regulatory filings or applications; (3) whether the facilities have a common generator lead line, electrical infrastructure, or interconnect at the same or nearby point or substations; (4) whether the facilities have a common land lease or land rights; (6) whether the facilities have common financing; or (7) whether the facilities are part of a common development plan or permitting effort.

In Order No. 732, however, FERC declined to adopt EEI's request on the grounds that it was beyond the scope of the rulemaking proceeding. Order No. 732, 130 FERC ¶ 61,214, P 45 (2010). FERC did not address EEI's substantive concerns regarding the implementation of the one-mile rule.

EEI has included PURPA modernization language as part of its statement for the record on the energy infrastructure legislation considered by the Committee during its May 14, 2015 hearing (See Attachment A). That proposed legislative language includes a proposal to address gaming of the one-mile rule. Berkshire Hathaway Energy (BHE) supports EEI's PURPA modernization language and believes that implementing these changes would strike the proper balance to ensure that the original intent of PURPA – to promote legitimate small power producers – is preserved.

Question 3: *Do you believe PURPA's mandatory purchase obligation should be eliminated altogether? If not, why not?*

Response to Question 3: Electricity markets have changed significantly since 2005, when PURPA Section 210 was last amended. Attachment B contains a white paper commissioned by BHE that describes PURPA's background, evolution and current trends.

Natural gas prices and renewable energy technology costs have dropped dramatically while, at the same time, Environmental Protection Agency regulations have contributed to making much coal-based generation more expensive to operate. Many states have renewable portfolio standard mandates with increasing procurement requirements that have expanded opportunities for renewable energy developers. Distributed energy resources and the potential for micro-grids are increasingly popular with electricity consumers. Moreover, FERC's open access transmission and interconnection standards for large and small generators have worked extremely well, making it possible for a QF to sell its power to multiple buyers, not just the local utility.

As Congress debates energy legislation, some say PURPA and its mandatory purchase obligation are no longer needed and should be repealed. However, not all utilities operate in states where there is an organized market and not all state utility regulators require competitive bidding when a utility is looking to secure new or replacement power. In those states, PURPA and its mandatory purchase obligation still serve a useful public

purpose. However, BHE believes the changes in many other electricity markets since the 2005 PURPA amendments make a compelling argument for repealing a purchase mandate that was enacted 37 years ago. BHE believes Congress should adopt the following set of four PURPA modernization changes:

(1) Expand the definition of "comparable markets" that are eligible for termination of the mandatory purchase requirement to include voluntary, auction-based energy imbalance markets and other sub-hourly markets.

(2) Terminate the mandatory purchase obligation upon a state regulatory agency determination that (1) their electric utility has no need to acquire capacity or electric energy from a qualifying cogeneration or small power production facility within a given timeframe identified in its resource plan filed with such agency, or three years, whichever is longer, in order to meet its load serving obligation, or (2) the electric utility is subject to a state-required integrated resource planning (IRP) process and competitive procurement processes for long-term energy or capacity resources that provide an opportunity for QFs to compete for any resource need identified in the utility's IRP process.

(3) Eliminate the presumption in FERC regulations that QFs under 20 MW do not have nondiscriminatory access to markets, provided that the QF is eligible for service under a FERC-approved open access transmission tariff or a FERC-filed reciprocity tariff and FERC-approved interconnection rules, and can participate in competitive solicitations overseen by a state regulatory authority.

(4) Enable utilities to rebut FERC's assumption that QFs are independent for purposes of applying the 20- or 80-MW size limitations where the sites are located more than one mile apart by demonstrating that the facilities are part of a common enterprise.

EEI's PURPA modernization language (Attachment A) would accomplish these reforms. Each of these options would address an identified problem. Taken together, these reforms would benefit customers significantly, while assuring that QFs have meaningful opportunities to sell power in wholesale markets.

Question 4: *Do you believe the universe of eligible QFs should be expanded? Please explain.*

Response to Question 4: No, the universe of eligible QFs should not be expanded. Utilities that do not have relief from the PURPA mandatory purchase obligation must purchase power from a QF even if the power is not needed. Accordingly, utilities that have large amounts of QF power on their systems often must curtail or shut down cheaper generation in order to accommodate higher cost QF generation. As described in our written testimony, such is the case with BHE's PacifiCorp utility. PURPA contracts are also not subject to the same state regulatory commission planning and cost scrutiny as other resource decisions and thus expose customers to unnecessary higher costs and risks.

As Congress debates energy legislation, expanding the mandatory purchase obligation is unnecessary given changes to electricity markets that have occurred since the purchase mandate obligation was created 37 years ago.

BHE does not support bills—including S. 1202, introduced by Senator Shaheen; S. 1213, introduced by Senator King; and S. 1233, introduced by Senator Wyden—that would expand PURPA by requiring utilities to purchase electricity from QFs at prices in excess of avoided cost. With energy efficiency gains throughout the economy and new opportunities for customer generators, growth in customer electricity demand has slowed and many utilities simply do not need more generation.

If a utility does need new generation, including renewable energy, competitive solicitations overseen by state regulatory commissions are the best means for acquiring a least-cost supply. In addition, open transmission access, which did not exist when PURPA was passed in 1978, is available everywhere, providing new generators many options to sell their products. Forcing utilities to pay above avoided cost, including retail or other subsidized prices, to a preferred class of generators in excess of what it costs to produce or buy power from others harms customers and the economy in the form of higher electricity prices.

Question 5a: *In your testimony, you state that net metering has resulted in improper cost shifting for consumers.*

a. *Please explain how that works.*

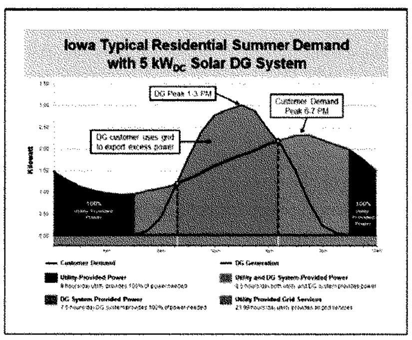
Response to Question 5a: Power produced by residential distributed generation systems connected to a utility's grid is compensated under existing tariff arrangements known as "net metering." Generally, net metering customers pay for the power they consume and are compensated for the power they produce at the retail price of electricity. The retail price for electricity includes costs associated for "grid services." (Grid services are also often referred to as fixed costs and include items like meters, wires, poles, and the vehicles service repair people drive to fix problems). Almost all of the costs for grid services are recovered from customers through a per-kilowatt-hour charge. Essentially, this means customers pay for these fixed costs based on how many kilowatt-hours they consume and without regard to when the power is acquired.

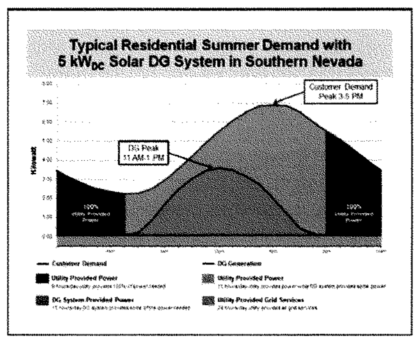
When distributed generation customers reduces their kilowatt-hour consumption because they are producing their own power (and getting paid for excess power), they ultimately pay less for "grid services." However, there is no corresponding reduction in the utility's costs for grid services because these fixed costs don't go away. All of the wires, poles, meters and vehicles are still necessary to continue to deliver the same safe and reliable power, even to those same customer generators who are never entirely off the grid. Instead, the loss in grid services revenue from owners of distributed generation systems must be made up by increasing the retail price paid by customers who do not have distributed generation systems. This is the "cost shifting" referred to in our written testimony.

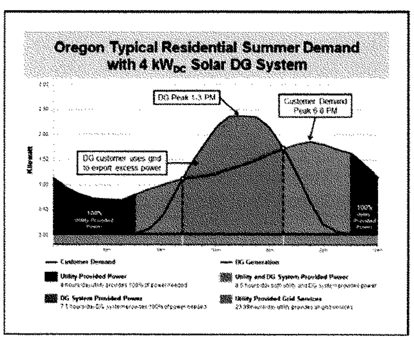
<u>Question 5b</u>: *In your testimony, you state that net metering has resulted in improper cost shifting for consumers.*

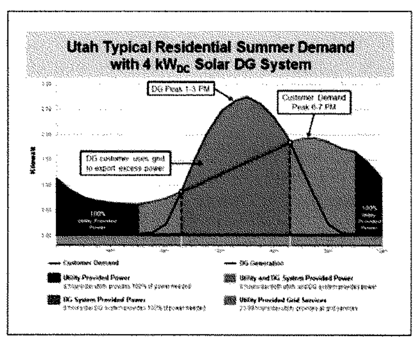
b. Is it fair for customers without rooftop solar panels to subsidize those that can afford to put solar on their homes?

<u>Response to Question 5b</u>: I describe this cost shifting as improper because BHE does not believe it is fair for customers with distributed generation systems to shift the burden of paying for grid services to customers who do not have such systems. As distributed generation grows, it is important to remember that distributed generation customers are still dependent on the utility's grid services. This is the case when a distributed generation customer is not capable of producing all the power they need like at night, on a cloudy day, or when an appliance (e.g., air conditioner, refrigerator, or washing machine) may require supplemental power during startup. It is also the case when a distributed generation customer with net metering exports excess power back to the grid. Residential distributed generation customers are a different type of customer, because they use the grid very differently, a point best illustrated on the graphs presented with our written testimony and reproduced below:









BHE believes that every customer who generates their own power should be compensated at a fair rate for the power they sell back to the grid. They should also pay a

fair price for use of the grid services upon which they rely. The system through new rate designs can be fixed in a way that creates fair rates for everyone who uses a utility's grid services. Our written testimony describes a three-component rate design as our preferred answer. We support the use of three-component rates for sales to distributed generation customers consistent with the cost of serving these "partial requirements" customers. The three components are a customer ($/monthly bill) charge; a demand (kW) charge, which measures how much power is used at any given point in time; and a power (kWh) charge, which measures the amount of electricity a customer uses over time.

The three-component rate design has been used for decades to serve commercial and industrial customers and is familiar to regulators, but has not been common for residential customers because they historically did not produce their own electricity. Residential customers are rarely subject to a bill with a demand charge. This is because, until recently, residential electricity loads were pretty much the same from one customer to the next. Residential customers generally used greater amounts of electricity during the morning hours, then went to work, and in the late afternoon or evening when they returned from work began using greater amounts of electricity until they went to bed, whereupon their usage declines significantly. With each customer in the residential class looking a lot like the next, utilities and state regulators bundled power and demand costs together into a single $/kWh price. However today, this assumption is no longer true. All residential customers are not the same; respective loads and consumption patterns are potentially very different.

A demand charge is based on the maximum amount of energy a customer uses at any one instance over the course of a billing cycle. It reflects the cost that a utility incurs to maintain the grid in standby mode in order to reliably deliver electricity the customer wants, when the customer wants it. The distinction between how much electricity you need right now and how much you need in total over time is important. Historically, this has only been important for large industrial and commercial customers that require high amounts of power throughout the day. But as the penetration of distributed generation to electric vehicle charging to programmable, controllable thermostats to stationary energy storage grows, the demand charge can be a solution to more equitably collect grid costs as well as create a price signal that encourages efficiency, load shifting and peak demand side management. BHE believes that separating out demand charges is a good way to promote a more fair cost allocation among customers while also motivating customers to reduce strain on the grid. Critically, it is now inexpensive to meter these differences, including time-of-use and the magnitude of the demand. Costs should be assigned among the components as nearly as practicable to reflect cost causation. A demand charge would more equitably charge each customer for the service required from the grid closer to each customer's true cost of service.

As described recently by the Rocky Mountain Institute:

> "Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited [distributed energy resources]. A demand

> charge more equitably charges customers for their impact on the grid, can reward [distributed generation] customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation." *See*, "Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?" by Matt Lehrman, Rocky Mountain Institute (May 21, 2015).[10]

Working together to define the rates will ensure the electric grid continues to be safe and reliable, while supporting a healthy and growing economy, including the continued growth of renewable energy sources and customer distributed generation options.

[10] See, http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design

Questions from Ranking Member Maria Cantwell

Question 1: *NV Energy received a major Department of Energy grant under the Smart Grid Demonstration program authorized in 2007 and funded in 2009 to install over 1 million smart meters in Nevada, along with the communications and demand response technology to take advantage of them. What benefits and lessons did you discover through this project for the grid and your customers?*

Response to Question 1: The NVEnergize program was initiated in 2009 and completed in 2014. The project involved the deployment of 1.23 million electric smart meters and 157,000 smart gas modules throughout the NV Energy statewide service area. The project included the deployment of a statewide smart grid communications network and implementation of secure back office systems and customer facing smart technologies. The project was supported by a Department of Energy (DOE) Smart Grid Investment Grant of $139 million. The total cost of the project was $325 million, with annual net benefits of over $19 million.

The project enabled operational efficiencies that resulted in reduced operations costs, fewer truck rolls, and associated reductions in emissions. The advanced technologies improved system reliability, thus allowing NV Energy to respond more efficiently and effectively to resolve emergency and reliability issues.

NVEnergize customer benefits include significantly enhanced information to customers, allowing them to make informed decisions about managing their energy use, lowering their energy bills, and reducing their energy-related impact on the environment. Voluntary time-based pricing, demand response programs, customer-selected due date, usage information and alerts, remote home controls, power outage notifications, and other services are enabled through two-way communications where advanced technology is installed.

NVEnergize has enabled immediate customer benefits by providing customers access to web- and mobile-based information about their usage and tools to manage that usage. The MyAccount web and mobile applications provide customers with an understanding of their usage patterns and the impact of changing usage patterns. The alerts function (email, text or phone) informs customers when various consumption and expenditure thresholds have been reached or a power interruption has accrued. Currently more than 50% of NV Energy's customers have signed up for the MyAccount portal.

Customer benefits from NVEnergize technology include:

- More accurate and prompt billing;
- Faster resolution of disputed bills;
- Better electricity service due to faster detection of and response to power outages;
- Reduction in energy theft;
- Improved convenience, security and privacy due to automated meter reading;

- More rate options and bill savings opportunities for customers because NVEnergize enables voluntary dynamic pricing; and
- Facilitation of the smart grid by connecting consumers to alternative pricing programs and home area network technologies such as smart thermostats.

NVEnergize also implemented a Consumer Confidence Plan (CCP) to ensure that the NVEnergize solution is secure, a consumer's privacy is maintained, meters are accurately measuring electricity usage, consumers are informed when their smart meters were to be installed, and consumers can verify these assertions. Ultimately, it allows consumers to take ownership of their electricity usage. These steps serve to increase consumer confidence in the NVEnergize program. NV Energy entered into the CCP to encourage consumer acceptance of smart grid technology and related services. Under the CCP, the utility is obligated to demonstrate the performance of the customer facing smart meter infrastructure to boost consumer confidence.

In August 2010, with the encouragement of the DOE, NV Energy submitted a proposal for the development and implementation of the CCP. In September 2010, the DOE approved NV Energy's proposal and awarded a matching Smart Grid Investment Grant increase of $1 million to implement the CCP. NV Energy implemented the plan to give consumers confidence that the NVEnergize systems are accurate, secure, and will prove beneficial to the consumer.

The CCP incorporates six main steps: security, privacy, system accuracy, deployment, system verification, and customer ownership.

Cybersecurity – NV Energy recognizes that along with significant benefits, smart technologies create significant new risks. On January 22, 2010, NV Energy filed its Cyber Security Plan (CSP) with the DOE as required by the Smart Grid Investment Grant. On February 1, 2010, the DOE approved this plan. The CSP is a living plan that outlines an ongoing and evolving approach to ensure cybersecurity of the NVEnergize implementation. NV Energy's implemented cybersecurity plan has specific measures to safeguard customer data, including: the use of firewalls to compartmentalize and control the smart grid network traffic; segregation of the smart grid networks from the corporate network using virtual private networks; secure configurations of the smart grid network components; encryption of interval traffic traversing the smart grid network; security monitoring of the smart grid network for abnormal network traffic behavior and specific attack signatures; and extensive third-party security testing of the smart grid components.

NV Energy employs dedicated cybersecurity personnel to conduct continuous monitoring of the network to detect potential breaches. Log accumulation and integration look for events that may indicate that there is a problem on the system, and regular audits and oversight functions are conducted to ensure that management of the computer systems is appropriate.

NVEnergize initially envisioned firewalls at the utility's core data centers. Data security experts collaborated with NVEnergize to formulate ways to improve protections over the

meter data in the utility's communications systems. In an effort to implement a more robust security system, redundant firewalls were added at each of the project's communication towers. These firewalls establish a secure virtual private network connection to counterpart firewalls in the NV Energy data center. This connection encrypts all the network traffic that is passed between the head end system and the communication towers, which prevents a compromise of the smart grid network via the corporate network. Firewalls also limit the network ports and protocols that are allowed to pass to and from the smart grid network. As discussed above, NVEnergize also accelerated the encryption of electric smart meter endpoints.

NV Energy also hired a third-party smart grid security testing firm (Wurldtech) to provide security testing of NV Energy's smart grid network. The purpose of this assessment was to determine the ability of the smart grid devices to maintain operational integrity and functional performance under real-world network conditions, such as abnormal traffic variations and simulated malicious attack scenarios. For each tested device, the security assessment team examined the physical security characteristics, hardware/software protection schemes, network communication robustness, fault-tolerances, and failure-modes to determine the overall security posture of the system.

Privacy – NV Energy is aware of and takes seriously the privacy concerns expressed regarding the smart grid implementations nationwide. NV Energy complies with and will continue to comply with NAC 704.320, sub 3 and does not share customer information for commercial purposes. NV Energy continues to evaluate the type of data collected and how it is secured at every stage of its lifecycle. In many cases, NV Energy is adding protections above those required by law, including securing data whether or not it contains sensitive information. At the direction of the Nevada Public Utilities Commission, NV Energy periodically reviews its privacy policies and identifies and implements, as appropriate, additional measures needed to ensure the continued protection of customer data. An NV Energy committee was formed and meets quarterly to monitor privacy of customer information.

Question 2: *The Quadrennial Energy Review discussed how the grid is vulnerable to the loss of large power transformers and could benefit from a strategic reserve. As a company with utilities in multiple states and major transmission assets, do you have a view on the value of this type of reserve?*

Response to Question 2: Individual utilities use risk-based approaches to determine appropriate sparing strategies for transformers, as we do for other items used in responses to incidents such as severe weather. BHE is participating in numerous industry efforts that address spare transformers, other critical spare items and movement of those items. BHE is strongly invested in these programs; we were among the founding industry members and continue to provide leadership. The Electric Sub-sector Coordination Council (ESCC), a Department of Homeland Security-chartered government-industry security policy group under the National Infrastructure Protection Plan, is also engaged in taking potential actions to address large power transformer risk beyond the industry's mitigation efforts.

Stockpiling of transformers is one potential risk management tool, but may not be the solution for all types of equipment or be useable in all scenarios. BHE will continue to evaluate transformer stockpiling options as part of potential industry solutions, as well as other protection measures, with the objective to provide reliable secure service to customers in a cost-effective fashion.

As I mentioned during the hearing's question and answer, EEI is pursuing a list of action items regarding expediting the movement of large transformers following a major regional or national event. Examples include engaging federal agencies in developing contingency plans, coordinating better with railroads, and reviewing Department of Defense airlift capability. Finding ways to expedite the movement of large transformers seems like an area where Congress could provide some assistance to industry.

Question 3: *Can you explain how small independent power producers would compete without the mandatory purchase requirement of PURPA in an energy imbalance market?*

Response to Question 3: As detailed in our written testimony, QFs of all sizes have meaningful access today to sell capacity, including long- and short-term sales, and electric energy, including long- and short-term sales, to buyers other than their local, interconnecting electric utility to the extent that utility participates in an organized market, an energy imbalance market or other sub-hourly market. Where such processes exist, a QF can also participate in a utility's competitive solicitations overseen by a state regulatory authority. In such scenarios, continuation of the PURPA mandatory purchase obligation is unwarranted because the above conditions provide QFs comparable outlets to make such sales, thus rendering the mandatory purchase obligation unnecessary.

Further, FERC-mandated generation interconnection and open access transmission rules ensure that independent power producers of all sizes have non-discriminatory access to the electric grid. FERC's Order Nos. 2003[11] and 2006[12] establish standard procedures and a standard interconnection agreement for large (>20 MW) and small generators, respectively. The regulations apply to independent power producers and incumbent utility resources alike. As a result, interconnection issues for all wholesale power producers are no longer barriers to entry, which was one of the concerns behind the need for PURPA when it was first enacted. Once interconnected, a QF can choose to sell its output to any utility to which it can deliver firm power. Additionally, FERC-mandated open access

[11] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004) (Order No. 2003-A), *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2005) (Order No. 2003-B); *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005); *see also* Notice Clarifying Compliance Procedures, 106 FERC ¶ 61,009 (2004).

[12] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 FR 34100 (Jun. 13, 2005), FERC Stats. & Regs. ¶ 31,180 (2005) (Order No. 2006), *order on reh'g*, Order No. 2006-A, 70 FR 71760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005), *order on clarification*, Order No. 2006-B, 116 FERC ¶ 61,046 (2006).

transmission rules ensure independent power producers of all sizes have adequate non-discriminatory access to the electric grid.

Thus, with no operational constraints or transmission or interconnection issues to prevent it from selling its output to a third party, a small independent power producer embedded in a given region with an energy imbalance market can compete without the mandatory purchase requirement just as it does today in independent system operator and regional transmission organization market regions where the mandatory purchase obligation has been terminated. That is to say such entities would compete for a utility's new capacity needs by bidding to provide imbalance energy into the market in the same manner as other wholesale power producers would and supply awards would be based on least-cost.

Questions from Senator Ron Wyden

<u>Question 1</u>: *In your opinion, what are the top three things that could be done to expand capacity and ancillary services markets to include resources such as energy efficiency, distributed generation and demand response?*

<u>Response to Question 1</u>: First, do no harm. Do not impose capacity markets in the western United States. The western United States does not have capacity markets. State managed Integrated Resource Plan (IRP) processes are rigorous and effective for identifying capacity resource needs and options including renewables, dispatchable thermal, storage, energy efficiency, distributed generation, and demand response. PacifiCorp already includes energy efficiency, distributed generation, and demand response in its IRP, which is reviewed by its six state regulatory commissions to determine timing and type of new capacity needs (i.e., the rigorous process that is absent in PURPA). Indeed, PacifiCorp plans to meet 86% of its projected incremental load growth for the next 10 years with incremental energy efficiency resources that it funds through its state-regulated demand-side management programs. In Oregon, these industry leading programs are managed by the Energy Trust of Oregon.

Second, ensure markets reflect accurate price signals. Well-functioning markets need good price signals. Reliable markets need reliable products with clear definitions and contracts. The key to allowing energy efficiency, distributed generation, and demand response products to receive proper price signals is to change utility rate design at the retail level. Current volumetric retail rate (kWh) design does not provide good price signals, because it inaccurately communicates that energy is worth the same every moment of the day and does not differentiate for time of use or for the ability to turn on or off with short or no notice. It also results in different classes of customers inadvertently subsidizing other customers – known as "cost-shifting" – instead of each customer paying or receiving payment for their actual cost or value contribution, i.e., the utility's actual avoided cost.

BHE believes that every customer who generates their own power should be compensated at a fair rate for the power they sell back to the grid. They should also pay a fair price for use of the grid services upon which they rely. The system through new rate designs can be fixed in a way that creates fair rates for everyone who uses a utility's grid services. Our written testimony describes a three-component rate design as our preferred answer. We support the use of three-component rates for sales to distributed generation customers consistent with the cost of serving these "partial requirements" customers. The three components are a customer ($/monthly bill) charge; a demand (kW) charge, which measures how much power is used at any given point in time; and a power (kWh) charge, which measures the amount of electricity a customer uses over time.

The three-component rate design has been used for decades to serve commercial and industrial customers and is familiar to regulators, but has not been common for residential customers because they historically did not produce their own electricity. Residential customers are rarely subject to a bill with a demand charge. This is because, until

recently, residential electricity loads were pretty much the same from one customer to the next. Residential customers generally used greater amounts of electricity during the morning hours, then went to work, and in the late afternoon or evening when they returned from work began using greater amounts of electricity until they went to bed, where their usage declined significantly. With each customer in the residential class looking a lot like the next, utilities and state regulators bundled power and demand costs together into a single $/kWh price. However today, this assumption is no longer true. All residential customers are not the same; respective loads and consumption patterns are potentially very different.

A demand charge is based on the maximum amount of energy a customer uses at any one instance over the course of a billing cycle. It reflects the cost that a utility incurs to maintain the grid in standby mode in order to reliably deliver electricity the customer wants, when the customer wants it. The distinction between how much electricity you need right now and how much you need in total over time is important. Historically, this has only been important for large industrial and commercial customers that require high amounts of power throughout the day. But as the penetration of distributed generation to electric vehicle charging to programmable, controllable thermostats to stationary energy storage grows, the demand charge can be a solution to more equitably collect grid costs as well as create a price signal that encourages efficiency, load shifting and peak demand side management. BHE believes that separating out demand charges is a good way to promote a more fair cost allocation among customers while also motivating customers to reduce strain on the grid. Critically, it is now inexpensive to meter these differences, including time-of-use and the magnitude of the demand. Costs should be assigned among the components as nearly as practicable to reflect cost causation. A demand charge would more equitably charge each customer for the service required from the grid closer to each customer's true cost of service.

As described recently by the Rocky Mountain Institute:

> "Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited [distributed energy resources]. A demand charge more equitably charges customers for their impact on the grid, can reward [distributed generation] customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation." *See*, "Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?" by Matt Lehrman, Rocky Mountain Institute (May 21, 2015).[13]

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[13] See, http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design

Third, support measures to expand competitive markets like the western energy imbalance market (EIM)[14] that can leverage demand response, such as through the proposed PURPA modernization amendment to extend PURPA's existing comparable markets mandatory purchase obligation exemption to the western EIM participants. PacifiCorp has several hundred megawatts of industrial demand response at its disposal in the new western EIM that displaces the need for more expensive traditional energy sources to balance changes in renewable resource output and load. As the western EIM expands, other demand response will be able to be utilized to deliver the customer benefit "trifecta" – lower costs, improved reliability, and reduced emissions.

Question 2: *I would like to make sure that as we develop the grid infrastructure of the future, we continue to protect the privacy rights of American citizens. Can you talk about some of the key ways in which we can hit the sweet spot of both tapping the potential of the smart grid while protecting privacy?*

Response to Question 2: BHE takes very seriously the protection of customer information and the security of both our electrical grid infrastructure and the communication and metering equipment utilized to support smart grid functionality. For example, in addition to our extensive internal corporate policies to protect customer information and the technology we utilize to protect it (including encryption of data and utilizing a proprietary communication channel for smart grid communications), NV Energy complies with a broad range of state and federal statutes to further ensure customer privacy. These include requirements to destroy customer records containing personal information (NRS 603A.200), limitation of disclosure of personal information to contractors (NRS 603A.210), and a strict prohibition of conveyance of personal information through electronic means (NRS 603A.215). In addition, NV Energy has a strong compliance program that ensures adherence to:

- The Electronic Communications Privacy Act;
- The Fair Credit Reporting Act;
- The Fair and Accurate Credit Transactions Act;
- The Federal Identity Theft Assumption and Deterrence Act; and
- All applicable security requirements of the Federal Energy Regulatory Commission.

As a highly regulated entity fully committed to our customers and the integrity of both our secure information systems and the operation of our electrical grid, BHE is confident that we have taken all possible measures to both adhere to the applicable laws, but more importantly to protect the security of our customers' information in a robust and aggressive manner. We understand and agree with the principle of protecting customer privacy and take that into account as a non-negotiable tenet of the current operation of our system and any future utilization of our smart grid technologies.

[14] See, http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx

Attachment A – EEI's PURPA Modernization Act

To update the Public Utility Regulatory Policies Act of 1978

A BILL

To modernize the Public Utility Regulatory Policies Act of 1978 to clarify circumstances in which the mandatory purchase requirements shall be terminated and to reduce opportunities for gaming

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. LOCATION OF QUALIFYING SMALL POWER PRODUCTION FACILITIES.

(a) REBUTTABLE PRESUMPTION. – The Federal Energy Regulatory Commission shall, within 180 days after enactment, amend its regulations implementing section 3(17)(A)(ii) of the Federal Power Act, 16 U.S.C. 796(17)(A)(ii), regarding the method for determining whether facilities are considered to be located at the same site as the facility for which qualification is sought for the purpose of calculating power production capacity, to provide a rebuttable presumption that two or more qualifying facilities are independent where the sites are located more than one mile apart.

(b) OVERCOMING THE PRESUMPTION. – In amending its regulations, the Commission shall allow any interested party to rebut the presumption in subsection (a) upon a showing that two or more facilities that are more than one mile apart are part of a "common enterprise." Factors that may be considered in determining whether an enterprise is part of a "common enterprise" for purposes of rebutting the presumption shall include the following:

(1) Whether the facilities have at least one common or affiliated owner or developer;

(2) Whether the owner(s) or developer(s) have treated the facilities as a single project for purposes of other regulatory filings or applications;

(3) Whether the facilities use the same energy resource;

(4) Whether the facilities have a common generator lead line, electrical infrastructure, or interconnect at the same or nearby point or substations;

(5) Whether the facilities have a common land lease or land rights;

(6) Whether the facilities have common financing; or

(7) Whether the facilities are part of a common development plan or permitting effort, even if the interconnection of the facilities occurs at separate points.

SECTION 2. TERMINATION OF MANDATORY PURCHASE REQUIREMENTS.

Section 210(m) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3(m)) is amended as follows:

(a) IDENTIFICATION OF COMPARABLE MARKETS. – Paragraph (1)(C) is amended

(1) by striking "for the sale of capacity and electric energy" and "at a minimum," in the first sentence; and

(2) by adding at the end thereof the following: "For purposes of this subsection, wholesale markets that are of comparable competitive quality shall include any independently administered, voluntary, auction-based energy imbalance market or other sub-hourly market, without regard to whether (A) an applicable electric utility participating in such markets is a member of a Regional

Transmission Organization or an Independent System Operator; or (B) such a market has a governance structure and operation that is wholly separate and autonomous from a Regional Transmission Organization or an Independent System Operator."

(b) PRESUMPTION OF NONDISCRIMINATORY ACCESS. – Subsection (1) is amended by adding at the end thereof the following new paragraph: "(D) For purposes of this subsection, qualifying facilities of any size are presumed to have nondiscriminatory access to the wholesale markets described in subparagraphs (A), (B) or (C) if the qualifying facility is (i) eligible for service under a Commission-approved open access transmission tariff or a Commission-filed reciprocity tariff and Commission-approved interconnection rules; and (ii) can participate in a competitive resource procurement process overseen by a State regulatory agency having ratemaking authority."

SECTION 3. RECOGNITION OF STATE DETERMINATIONS.

Section 210(m) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3(m)) is further amended—

(a) by redesignating paragraphs (3), (4), (5), (6), and (7) as paragraphs (4), (5), (6), (7), and (8), respectively;

(b) by inserting after paragraph (2) the following:

"(3) State Determination.—After the date of enactment of this paragraph, no electric utility shall be required to enter into a new contract or legally enforceable obligation to purchase capacity or electric energy from a qualifying cogeneration facility or a qualifying small power

production facility under this section if the State regulatory agency having ratemaking authority over the electric utility has determined that: (i) the electric utility has no need to acquire capacity or electric energy from such qualifying cogeneration or small power production facility within the given timeframe identified in its resource plans filed with such State regulatory agency, or three years, whichever is longer, in order to meet its obligation to serve customers in the public interest; or

(ii) the electric utility is subject to a state required Integrated Resource Planning (IRP) process and competitive resource procurement process for long-term energy or capacity resources that provides an opportunity for qualifying cogeneration or qualifying small power production facilities to compete for any resource need identified in the electric utility's IRP process."

(c) in paragraph (4) (as so redesignated)—

(A) in the second sentence, by striking "of this subsection"; and

(B) by inserting "or in paragraph (3)" after "paragraph (1)" each place it appears; and

(d) in paragraph (5) (as so redesignated)—

(A) in the first sentence, by striking "paragraph 3" and inserting "paragraph (4)";

(B) in the second sentence, by striking "of this subsection"; and

(C) by inserting "or in paragraph (3)" after "paragraph (1)" each place it appears.

Attachment B - Public Utility Regulatory Policies Act (PURPA)
Background, Evolution, Current Trends

The Public Utility Regulatory Policies Act of 1978 (PURPA)[15] was enacted to increase the country's energy independence and decrease reliance on foreign oil by promoting increased energy conservation and efficiency. Since its enactment, PURPA has helped reduce U.S. dependence on foreign oil by promoting increased use of energy conservation and efficiency and renewable resources. Renewable generation in the U.S. has increased significantly since PURPA's passage, due to the Federal Energy Regulatory Commission's (FERC's) policies and because many renewable PURPA projects also benefit from financial incentives in the tax code, state renewable portfolio standard requirements, technological improvements,[16] and stricter Environmental Protection Agency air emission regulations.

Section 210 of PURPA directed FERC to prescribe rules necessary to encourage cogeneration and small power production facilities (Qualifying Facilities or QFs). FERC's rules include provisions for administering PURPA's mandatory purchase obligation, calculating the purchase price or "avoided cost"[17] of power and for determining the size of a QF, based on a "one-mile rule."[18]

PURPA as it exists today, however, has out served its usefulness and it is imposing significant and unnecessary costs on consumers. For some time now, due to the evolution of the electricity markets since PURPA's enactment, and implementation of new standardized interconnection and transmission rules, the need for the mandatory purchase obligation is no longer necessary. Prior attempts to restrict PURPA, such as in the Energy Policy Act of 2005's (EPAct 2005) addition of Section 210(m) to terminate the mandatory purchase obligation, have not been fully successful in eliminating the consumer harm.

The following discussion will examine the background and history of PURPA, including the guidelines for determining avoided cost, implementation of FERC's regulatory policies, and the evolution of the implementation of the mandatory purchase obligation since the passing of EPAct 2005. The discussion will also explore the need for further modifications of PURPA that are in the public interest.

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[15] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95–617, 92 Stat 3117 (1978).

[16] *See* PETER KIND, DISRUPTIVE CHALLENGES: FINANCIAL IMPLICATIONS AND STRATEGIC RESPONSES TO A CHANGING RETAIL ELECTRIC BUSINESS 4 (Edison Electric Institute 2013).

[17] The incremental cost of electric energy or capacity, which, but for the purchase from the QF, the utility would itself generate or purchase. 18 C.F.R. § 292.101(b)(6).

[18] The size of a QF is measured together with other facilities within one mile that use the same energy resource and are owned by the same person or its affiliates. 18 C.F.R. § 292.204(a).

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DISCUSSION

I. Congress' Intent in Passing the Public Utility Regulatory Policies Act's (PURPA) Mandatory Purchase Obligation in 1978

Congress enacted PURPA in 1978 in reaction to the ongoing oil crisis.[19] Its overall stated goal is to create "a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers." According to the legislative history, these goals are all independent of one another. While it is not necessary for them all to be met in any given regulatory action, any goal that is met cannot negatively impact another.[20] FERC is the regulatory agency given authority to enact and enforce PURPA along with state regulatory commissions.[21]

Congress wanted to encourage growth in the renewable energy sector.[22] To achieve this growth, Congress desired to overcome the reluctance of utility companies "to purchase power from, and to sell power to, the nontraditional facilities."[23] To that end Section 210 of PURPA requires utility companies to purchase electricity offered for sale by small qualifying facilities at rates "just and reasonable to the electric consumers . . . and in the public interest."[24] PURPA further encouraged growth in this sector by exempting very small producers (those whose power production capacity is not more than 30 MW) from regulations promulgated under the Federal Power Act (FPA), the Public Utility Holding Company Act (PUHCA) and various state utility regulations.[25] QFs are defined as either cogenerators or small power producers (SPPs).[26] Cogenerators simultaneously produce electricity and another form of energy, such as steam or heat.[27]

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[19] *FERC v. Mississippi*, 456 U.S. 742, 756, 102 S. Ct. 2126, 2135, 72 L. Ed. 2d 532 (1982) ("Committees in both Houses of Congress noted the magnitude of the Nation's energy problems and the need to alleviate those problems by promoting energy conservation and more efficient use of energy resources."); Lori Anne Orndorff, *Idaho's Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, 30 IDAHO L. REV. 177 (1994).

[20] Joint Explanatory Statement of the Committee of Conference, House Conference Report No. 95-1750, at 7803 (1978).

[21] 16 U.S.C. § 824a-3(a) ("Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons.").

[22] *FERC v. Mississippi*, 456 U.S. 742 at 750. Note that this case is sometimes cited for the quote that Congress intended PURPA to "reduce demand for traditional fossil fuels." Justice Blackmun, writing for the majority, did not cite PURPA or any other source in making this observation. PURPA itself does not mention the use of "fossil fuels" at all. FERC, however, in its final rule's preamble declared that that's what Congress intended. *See* 45 Fed. Reg. 12214, 12215.

[23] *Id.*

[24] 16 U.S.C. § 824a-3.

[25] 16 U.S.C § 824a-3(e).

[26] 16 U.S.C. § 824a-3(a).

[27] 16 U.S.C. § 796(18)(A).

Small power producers are generators whose primary fuel input derives from renewable sources such as biomass or wind, and they must have a production capacity of not more than 80 MW.[28]

II. FERC's Guidelines for Determining an Electric Utility's Avoided Cost Pursuant to PURPA

PURPA requires FERC to set rates that utilities must pay to QFs for their power. FERC granted state regulatory authorities flexibility in determining a utility's actual avoided cost. These rates nevertheless had to be "just and reasonable" and "nondiscriminatory" and could not exceed the "incremental cost to the electric utility of alternative electric energy."[29] As a result, avoided cost calculation methodologies vary from state to state and oftentimes within jurisdictions.

A. Avoided Cost Defined

PURPA requires regulated and nonregulated[30] utilities to purchase all energy and capacity from QFs at rates that are just and reasonable to the electric consumers, in the public's interest, and nondiscriminatory against qualifying facilities.[31] PURPA directed that no QF rate should exceed the incremental cost to the electric utility of alternative electric energy, which means the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. Further, PURPA stated that regulations should include provisions regarding minimum reliability of both QFs and electric utilities, particularly during emergencies.[32]

Subsequently, FERC adopted regulations that defined "incremental cost" to equal a utility's full avoided cost to an "electric utility of electric energy[33] or capacity or both[34]

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[28] 16 U.S.C. § 796(17)(A). When PURPA was passed in 1978 and when FERC issued its rules implementing the small power production provision in 1980, "wind" was not expressly listed as a fuel source although likely was intended to be included in the phrase "renewable resources." "Wind" was expressly included in the 1990 amendments to Section 210.

[29] PURPA Section 210(b).

[30] PURPA created a category called "nonregulated utility" (such as a municipally owned power system that is not subject to the Federal Power Act and thus can sell power at wholesale outside of FERC's jurisdiction). Nonregulated utilities are required to both establish avoided cost rates (similar to a state regulatory commission) and purchase QF energy and capacity (similar to a purchasing utility). 16 U.S.C. § 824a-3(f)(2).

[31] 16 U.S.C. § 824a-3.

[32] *Id.*

[33] Energy costs are the variable costs associated with the production of electric energy such as fuel price and some operating and maintenance costs. Capacity costs are "the costs associated with providing the capability to deliver energy . . . primarily the capital costs of facilities." 45 Fed Reg. 38,12214, 38,12216 (Feb. 25, 1980).

[34] If a utility is able to avoid purchasing energy from another source by purchasing energy from the QF, the avoided cost should be based on the utility's avoided energy costs. Similarly, if a utility is able to avoid

which, but for the purchase from the QF, such utility would generate itself or purchase from another source."[35] In rejecting several split-cost proposals, FERC acknowledged that setting a utility's QF rate at the *full* avoided cost, the maximum rate allowed by PURPA,[36] would provide no cost savings to electric consumers; however, FERC reasoned that at its early stage of implementation, the maximum rate would provide "the greatest incentive for the development of cogeneration and small power production . . . [and] that the entire country [would] ultimately benefit."[37]

FERC provided QFs with the option of an avoided cost rate that varies over the life of the contract (non-levelized rate) or a rate that is estimated at the time the QF creates a "legally enforceable obligation" and is fixed over the life of the contract (levelized rate).[38] Levelized rates essentially result in the electric utility overpaying in early years and underpaying in later years, and several states view levelized rates as an incentive to QF development because it provides QFs with upfront financing to reduce the project's risk.[39] Long-term cost estimates will inevitably vary from actual costs; however, FERC reasoned that overestimation and underestimation over time would eventually balance out.[40]

PURPA, however, was not intended to subsidize QF projects. FERC emphasized that a utility should not pay a rate above its full avoided cost and even authorized state regulatory authorities to set rates below a utility's avoided cost as long as the rate was "sufficient to encourage cogeneration and small power production."[41] In order to determine the QF's "individual and aggregate value"[42] to the utility's system, FERC provided a list of factors that could result in upward or downward adjustment of the avoided cost. The list of factors include:

(1) the ability of the utility to dispatch the QF;

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constructing a generating unit by purchasing energy from a QF, that utility's avoided cost would be based on the utility's avoided capacity and energy costs. *Id.*

[35] 18 C.F.R. § 292.101(b)(6).

[36] The maximum rate only applies to rates mandated by the state. A QF can negotiate a rate with a utility that exceeds its avoided cost. SCOTT HEMPLING, ET AL., RENEWABLE ENERGY PRICES IN STATE-LEVEL FEED-IN TARIFFS: FEDERAL LAW CONSTRAINTS AND POSSIBLE SOLUTION, (Nat'l Renewable Energy Lab. Jan. 2010).

[37] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (1983) (emphasis added).

[38] *See* HEMPLING *supra* note 22.

[39] CAROLYN ELEFANT, REVIVING PURPA'S PURPOSE: THE LIMITS OF EXISTING STATE AVOIDED COST RATEMAKING METHODOLOGIES IN SUPPORTING ALTERNATIVE ENERGY DEVELOPMENT AND A PROPOSED PATH FOR REFORM, 33 (2011).

[40] 18 C.F.R. § 292.304(b)(5) ("In the case in which rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.").

[41] 18 C.F.R. § 292.304(b)(3).

[42] 45 Fed. Reg. 38,12214, 38,12224 (Feb. 25, 1980).

(2) the expected or demonstrated reliability of the QF;
(3) the terms of any contract, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
(4) the extent to which scheduled outages of the QF coordinate with the utility's scheduled outages;
(5) the usefulness of energy and capacity supplied by the QF during system emergencies;
(6) the individual and aggregate value of energy and capacity from the QF on the utility's system;
(7) the smaller capacity increments and shorter lead times available with additions of capacity from the QF;
8) the relationship between a QF's production and a utility's ability to actually avoid costs; and
(9) costs or savings from changes in line losses as a result of purchases from QFs.[43]

In response to FERC's concern that the transaction costs of negotiating a project-specific contract would make a small QF financially infeasible, FERC required all utilities to offer standard rates to small QFs with a design capacity of 100 kW or less.[44] Standard rates were designed to encourage the development of small QFs "by giving them a published, 'set' price that they could use to evaluate the economics of their project."[45] FERC required these standard rates to reflect the utility's avoided cost, but it granted the states the authority to offer standard rates to QFs larger than 100 kW and to differentiate among QFs "using various technologies on the basis of the supply characteristics of the different technologies."[46] Whereas a larger QF must negotiate a project-specific avoided cost rate with the utility, standard rates "tend to reflect a generic, and in some cases a state-wide, measure of avoided costs."[47] Standard contracts facilitate transactions and reduce the QF's transactional costs; thus, QFs tend to favor standard offer rates.[48] These standard rates have been controversial, for example, as discussed

[43] 18 C.F.R. § 292.304(e)(2)(3)(4); *see also* ROBERT E. BURNS AND KENNETH ROSE, PURPA TITLE II COMPLIANCE MANUAL 34 (Am. Pub. Power Ass'n, the Edison Electric Inst., the Nat'l Ass'n of Regulatory Util. Comm'r and the Nat'l Rural Electric Coop. Ass'n, March 2014).

[44] 18 C.F.R. § 292.304(c). Small Power Production and Cogeneration Facilities – Rates and Exemptions, Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, 45 Fed. Reg. 12223 (Feb. 25, 1980).

[45] FRANK GRAVES, PHILIP HANSER & GREG BASHEDA, PURPA: MAKING THE SEQUEL BETTER THAN THE ORIGINAL at 6 (Edison Electric Institute 2006).

[46] 18 C.F.R. § 292.304(c)(3).

[47] *See* GRAVES *supra* note 31, at 11.

[48] *Id.* at 9.

below, in Idaho where large wind developers began disaggregating large wind projects in order to qualify for Idaho's standard offer rates.[49]

B. PURPA's Avoided Cost Evolution

Notwithstanding PURPA's statutory language that the rates utilities must pay QFs cannot exceed its incremental costs, in order to further encourage QF development, many states have adopted policies that essentially result in utilities paying prices in excess of avoided cost rates. Although FERC has explicitly rejected QF rates in excess of avoided cost,[50] in 2010, FERC permitted states to implement certain policies that provide additional incentives for QF development. FERC found in *Southern California Edison* that an environmental "adder" (or bonus) could be included in the avoided cost rate if the environmental costs were not speculative but were "real costs that would be incurred by utilities."[51] FERC affirmed its decision in a subsequent clarification order and found that "if the CPUC bases the avoided cost [location] 'adder' or 'bonus' on the actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such 'adder' would constitute an actual avoided cost and would be consistent with PURPA."[52] In this same order, FERC noted that states may provide "additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate," by allowing QFs to retain renewable energy credits (RECs; also known as green tags).[53]

Also in 2010, FERC overturned its 15-year precedent in *California Public Utilities Commission* that involved a California feed-in tariff program intended to promote combined heat and power (CHP) projects. FERC found that where a state has adopted a policy to encourage a particular technology, the state can set avoided cost rates specific to that technology and does not have to take into account other sources when setting rates.[54]

III. State Regulatory Authorities—Calculation of Avoided Cost Rates and Policy Objectives.

Recognizing that the "economic and regulatory circumstances vary from state to state," FERC gave broad flexibility to state regulatory authorities to determine an

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[49] Idaho Commission Order No. 32176 (Feb. 2011) (reducing the eligibility cap for published avoided cost rates from 10 MW to 100 kW for only wind and solar QFs during investigation of the issue of disaggregation).

[50] *Conn. Light & Power Co.*, 71 FERC ¶ 61,035 (1995), *reconsideration denied*, 70 FERC ¶ 012 (1995) (finding that the "Commission's regulations bar the prescription of QF rates that exceed avoided cost").

[51] *S. Cal. Edison*, 133 FERC ¶ 61,059 (2010).

[52] *Cal. Pub. Utils. Comm'n*, 133 FERC ¶ 61,059 (2010), *granting clarification*, 132 FERC ¶ 61,047 (2010).

[53] *Id.* Permitting a QF to retain and sell RECs separately provides an additional source of revenue making projects more financially feasible. *See* ELEFANT *supra* note 25, at 34.

[54] *S. Cal. Edison*, 133 FERC ¶ 61,059 (2010).

appropriate method for calculating a utility's avoided cost.[55] Differing state policy and administrative considerations have therefore led to various avoided cost methodologies that differ from state to state and sometimes within jurisdictions.

Shortly after PURPA was enacted, most states held hearings to adopt an administratively determined avoided cost calculation methodology or to arrive at specific rates that represented the utility's avoided cost. By the mid-1980s, utilities were generally overpaying for QF energy and capacity,[56] and/or purchasing too much energy and capacity.[57] To address these issues, many states began adopting a competitive bidding method to either replace or supplement administrative methods. States generally have adopted avoided cost methods that fall into five categories.

Proxy or Committed Unit Method. The proxy unit methodology assumes that a QF allows a utility to delay or avoid constructing a future generating unit, and avoided cost rates are based on the estimated fixed (capacity) and variable (energy) costs of the next planned proxy unit.[58] States differ on their selection of a proxy unit.[59] Because the avoided cost is based on a specific unit, it does not take into account a utility's system marginal cost.[60] The proxy unit method is considered to be the simplest method, and thus it is one of the most common methods adopted.[61]

Peaker Unit Method. The peaker method assumes that the QF will allow the utility to avoid dispatching its most expensive (marginal) generating unit during the life of the contract, thus reducing the utility's marginal generation on its system and eliminating the need to build a peaking unit.[62] Capacity costs are estimated as the utility's least-cost capacity option that might be added to the system to increase the system

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[55] Order No. 69, 45 Fed. Reg. 12214, 12231 (Feb. 25, 1980).

[56] "All long-term estimates of avoided costs are critically dependent on underlying assumptions about fuel costs, demand growth, financing costs, labor and material costs, and permitting and siting costs." Among other factors, actual natural gas and oil prices turned out to be much lower than forecasted, resulting in "projected long-run avoided costs far in excess of realized avoided costs." *See* GRAVES *supra* note 31, at 12.

[57] E.P. Kahn, et al., *Evaluation Methods in Competitive Bidding for Electric Power*, LAWRENCE BERKELEY LAB. 26924 (June 1989) (finding that in many states, the capacity offered by qualifying facilities was often 10-20 times greater than the utility's capacity requirements).

[58] *See* GRAVES *supra* note 31, at 9.

[59] For example, Idaho uses a proxy unit method for standard contracts, and the proxy unit is a surrogate avoided resource (SAR) which is a hypothetical combined cycle combustion turbine (CCCT) unit. Idaho Commission Order No. 29124 (Sept. 2002). Florida, however, uses a proxy unit method for standard contracts based on the utility's next avoided unit in its Ten-Year Site Plan. Florida Administrative Code 25-17.250(1)(2)(a).

[60] *See* GRAVES *supra* note 31, at 9–10.

[61] One disadvantage of using the proxy unit method is that the avoided cost rate is heavily dependent on the proxy unit chosen; therefore, selecting a higher cost unit can result in higher avoided costs. *See* ELEFANT *supra* note 25, at 17; GRAVES *supra* note 31.

[62] *See* GRAVES *supra* note 31, at 10. This method "seeks to answer the question: What is the QF capacity worth in hours when the utility is short on capacity?" *Id.*

capacity at the time of the system peak, and energy costs are estimated as the marginal energy costs over the duration of the contract.[63] This method is data-intensive, requiring utilities to estimate its system marginal energy costs with and without the qualifying facility.[64]

Difference in Revenue Requirement (DRR). The DRR method calculates the difference in the utility's revenue requirement (total generation cost) with and without the QF's hypothetical capacity.[65] Generation expansion plans and revenue requirements are generated, both with and without the QF capacity. The difference in these two revenue requirements equals the utility's avoided cost, which includes avoided energy and capacity costs and other factors, such as taxes.[66] The DRR method is considered to produce more accurate results than other methodologies; however, the method has been criticized for being overly complex and lacking in transparency because the models available to utilities are less accessible to QFs.[67]

Market-based Pricing. States that have organized wholesale markets have used locational marginal pricing (LMP) to set avoided costs in those states. For example, Maryland, New Jersey, North Carolina and Virginia have approved the use of the PJM Interconnection (PJM) LMP pricing, Connecticut and New Hampshire have approved the use of the New England Independent System Operator (ISO-NE) LMP, and Kentucky and Michigan have approved the use of the Midcontinent Independent System Operator (MISO) LMP.[68] This method is typically available for energy costs or short-term capacity costs when a utility has excess capacity and consequently does not need to purchase capacity to meet system demand.[69] Other price benchmarks are also available today, such as forward price quotes provided by brokers and financial firms for all regions of the U.S.[70]

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[63] Whereas some utilities favor this method because capacity costs are lower, some states, such as Georgia, have rejected this method as an insufficient method for financing QFs because higher energy costs may not be adequate to account for the lower capacity costs over the term of the contract. *See* ELEFANT *supra* note 25, at 18 ("Financing is not available for a project with a revenue stream solely dependent upon energy payments that vary by the hour.")

[64] *See* GRAVES *supra* note 31, at 10.

[65] *Id.*

[66] *Id.* at 10-11.

[67] Some states, such as North Carolina, allow utilities to use the DRR method, but the approach is only used in a limited number of states. *See* ELEFANT *supra* note 25, at 19–20.

[68] *But see Exelon Wind I, LLC, et al.*, Notice of Intent Not to Act and Declaratory Order, 140 FERC ¶ 61,152 (2012). In that case, FERC held that it was inconsistent for SPS to use the SPP Energy Imbalance Market's locational imbalance prices at the particular QF's node as the avoided cost. It appears that the use of the QF's particular node for avoided cost purposes was objectionable, not the use of the SPP imbalance market itself, but that point is not abundantly clear in the order. In any event, that decision remains pending on rehearing since 2012.

[69] *See* ELEFANT *supra* note 25, at 20.

[70] *See* GRAVES *supra* note 31 at 27.

Competitive Bidding. Although states vary, a utility generally determines its capacity need through its Integrated Resource Plan (IRP) process, and the utility can either establish a benchmark price for QFs to bid to meet it or conduct a competitive bid and select winners based on specific bid criteria.[71] Bids also typically include non-price factors such as fuel diversity and environmental impacts.[72] In 1988, FERC issued three Notices of Proposed Rulemaking (NOPRs) related to avoided cost calculations, which were ultimately never implemented. The second NOPR (bidding NOPR) stated that bidding was an appropriate method for calculating avoided cost and even concluded that bidding addressed many of the issues related to administratively determined methods and could encourage more efficient QFs.[73]

In short, states have implemented various methods and policies to determine avoided costs and encourage QF development. Although FERC has intervened to provide guidance around certain state policies, such as environmental adders and when a legally enforceable obligation is created,[74] FERC has declined to intervene in state determinations of actual avoided cost rates.[75] In *Connecticut Light & Power Co.*, FERC stated that "whether the rate was, in fact, above avoided cost was best left to the appropriate state or judicial forum."[76] FERC's reluctance to review actual avoided cost rates suggests that states continue to have broad flexibility in adopting policies for QF development.

IV. EPAct 2005 and Other Amendments to PURPA

Originally, the requirement to purchase available energy from designated QFs was mandatory under all applicable circumstances.[77] However, due to the prevalence of "PURPA machines" – large non-utility cogeneration facilities that produced only a small amount of useful thermal energy for industrial or commercial purposes but required the local utility to purchase unneeded power – and given the various structural changes in the electric industry, including the move away from a single rate-regulated service provider in some parts of the United States to an open retail market for electricity, Section 210 was amended by Section 1253 of the EPAct 2005.[78] Under the 2005 amendment, a utility is relieved of its mandatory obligation to purchase energy for sale by QFs if it can show the

[71] The price of the winning bid would represent the utility's avoided cost. *See* ELEFANT *supra* note 25, at 20.

[72] *See* GRAVES *supra* note 31, at 23.

[73] Administrative Determination of Full Avoided Costs, Sales of Power To Qualifying Facilities, and Interconnection Facilities, Order Terminating Proceeding, 63 Fed. Reg. 51310-01 (Sept. 25, 1998).

[74] Complaint, *FERC v. Idaho Pub. Utils. Comm'n*, No. 1:13-cv-141 (D. Idaho 2013).

[75] Steven Ferrey, *Avoided Costs*, 1 L. OF INDEP. POWER § 7:9 (2013).

[76] 71 FERC ¶ 61,035 (1995), *reconsideration denied*, 70 FERC ¶ 012 (1995) (finding that the "Commission's regulations bar the prescription of QF rates that exceed avoided cost").

[77] 16 U.S.C. § 824a-3.

[78] Revised Regulations Governing Small Power Production and Cogeneration Facilities, Order No. 671, 71 Fed. Reg. 7852 at PP 37, 49 (Feb. 15, 2006).

QF has access to a competitive wholesale market.[79] If a competitive wholesale market is not available, then the mandatory purchase requirements remain in effect.[80]

Other provisions of the 2005 amendment also show a move away from mandatory obligations on behalf of the utility companies to a more competitive market approach. For example, prior to the amendment, a utility company was required to sell electricity to the QF as well as purchase electricity from them. In addition to no longer being obligated to buy electricity from a QF if certain market conditions exist, a utility is also no longer obligated to sell electricity to a QF if there are other "competing retail electric suppliers [that] are willing and able to sell and deliver electric energy to the [QF]."[81] The 2005 amendment also requires the primary purpose of a new cogeneration facility be for "industrial, commercial, or institutional purposes" not primarily for resale to utilities.[82] There is no similar provision for new small power generators, however, because, at that time, these small facilities were not producing significant amounts of unnecessary power.

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[79] Energy Policy Act of 2005, Pub. L. No. 109–58, § 1253, 119 Stat 594 (2005).

(m) Termination of mandatory purchase and sale requirements

(1) Obligation to purchase

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to--

(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

16 U.S.C. § 824a-3

[80] *Id.* There are several Independent System Operators and Regional Transmission Organizations in the country that provide a wholesale market for QFs. However, such organized markets do not cover all areas of the country. *See Regional Transmission Organizations (RTO)/Independent System Operators (ISO)*, (June 24, 2013) http://www.ferc.gov/industries/electric/indus-act/rto.asp.

[81] 16 U.S.C. § 824a-3 (m)(5)(A).

[82] 16 U.S.C. § 824a-3 (n)(1)(A)(ii). See also FERC's implementation of EPAct 1253's provisions requiring that the thermal output of new cogeneration facilities be used in a "productive and beneficial manner." Order No. 671 at PP 27-61. Order No. 671 also removed certain exemptions from FPA regulations that previously applied to certain QFs greater than 30 MW. Order No. 671 at P 96.

Therefore small generation facilities that use renewable sources such as wind, solar, or biomass can be built solely for resale of the generated electricity to utilities under PURPA.

The 2005 EPAct amendment is the most substantial amendment to Section 210 of PURPA and is the most recent. The first amendment to Section 210 came in 1980 and added language encouraging small power production from geothermal sources.[83] The next amendment to Section 210 came in 1986. This amendment added language concerning hydroelectric power.[84] In 1990 an original provision of Section 210 that allowed FERC to exempt very small QFs (those with maximum output of not more than 30 MW) from regulations under the FPA, the PUHCA, and state regulations was amended to allow larger solar, wind, waste, and geothermal facilities (those that produced up to 80 MW) to be exempt as well.[85]

V. Current PURPA Trends

There have been several trends occurring in recent years that indicate that PURPA's original intent to encourage independent generators is no longer necessary or useful. First, FERC has made it too difficult for utilities to obtain relief from the mandatory purchase obligation despite Congress' intent in enacting Section 210(m) in EPAct 2005 to limit that obligation. Second, FERC's one-mile rule for determining the size of a QF project, (*i.e.*, by considering all QFs by the same owner, using the same resource located within a mile), is creating gaming opportunities for renewable developers. Locating multiple wind projects, for example, just beyond one mile from each other enables developers to exceed the small power production size limitations. Third, with the advent of open access transmission across the country, QFs can choose to sell to utilities to which they are not directly interconnected if, for example, a neighboring state offers a more advantageous price structure. Fourth, FERC has implemented rules to ease the administrative burden for small residential facilities, but its one MW or less threshold has the effect of providing administrative relief to commercial QFs of significant size.

A. FERC's Implementation of EPAct 2005, Section 210(m), Regarding the Termination of the Mandatory Purchase Obligation is Too Restrictive and Causes Unnecessary Consumer Harm Given the Current Structure of the Electric Industry.

[83] *See* An Act to extend the Defense Production Act of 1950, and for other purposes, Pub. L. No. 96–294 § 643, 94 Stat 611 (1980).

[84] *See* An Act to amend the Federal Power Act to provide for more protection to electric consumers, Pub. L. No. PL 99–495, § 8, 100 Stat 1243 (1986).

[85] Solar, Wind, Waste, And Geothermal Power Production Incentives Act Of 1990, Pub. L. No. 101–575, § 2, 104 Stat 2834 (1990). The size exemption provided by this amendment was limited to certain renewable facilities that began construction by December 31, 1999. Congress has not extended the effects of this amendment; thus the original 80 MW size limit applies to new small power production facilities.

In 2006, FERC issued new rules to implement the new Section 210(m) to govern the removal of the mandatory purchase obligation. In Order No. 688 (and subsequent orders), FERC established certain presumptions based on a QF's size to determine whether a QF had access to an appropriate market.[86]

First, FERC created a rebuttable presumption that QFs larger than 20 MW have nondiscriminatory access in (1) the "Day 2 markets" operated by the Independent System Operators/Regional Transmission Organizations (ISO/RTOs) in the Northeast and Midwest and that members of the ISO/RTOs in those regions should be relieved of the obligation to purchase from QFs;[87] (2) the "Day 1 markets" operated by an RTO in the southwest along with having a meaningful opportunity to make short term sales;[88] and (3) the "comparable markets" operated by ISO/RTOs in California and Texas.[89] The evidentiary showings FERC established are higher for "Day 1 markets" than for "Day 2 markets" and highest for "comparable" markets due to the presumption that QFs there have fewer off-system sales opportunities respectively in these markets.

Second, FERC established a rebuttable presumption that QFs smaller than 20 MW lack nondiscriminatory access to an appropriate market – even if the QFs are located in one of the Day 2, Day 1 or comparable markets – unless a utility can make a facility-specific showing that each QF has nondiscriminatory access. In doing so, FERC concluded that "some, perhaps most, small QFs at or below the 20 MW level can be distinguished from larger QFs by the type of delivery facilities to which they typically interconnect" and smaller QFs are also "more likely to have to overcome other obstacles, such as jurisdictional differences, pancaked rates, and perhaps additional administrative procedures, to obtain access to distant buyers."[90] This presumption of no access for QFs smaller than 20 MW has made it exceedingly difficult for utilities to avoid purchasing from QFs that could be as large as 20 MW, without any limit on the number of QFs and regardless of whether the power is needed.

Third, FERC expressly noted the relevance of transmission-related access and that constraints impact a potentially-affected QF's access to the wholesale market such that

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[86] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 71 Fed. Reg. 64342 (Nov. 1, 2006), FERC Stats. & Regs. ¶ 31,233 (2006), *order on reh'g*, 119 FERC ¶ 61,305 (2007) (Order No. 688-A).

[87] Order No. 688 at P 102; 18 C.F.R. § 292.309(e). The ISOs/RTOs in the Day 2 regions are: New York Independent System Operator, Inc. (NYISO), ISO New England, Inc. (ISO-NE), PJM Interconnection, L.L.C. (PJM), Midcontinent Independent System Operator, Inc. (MISO).

[88] Order No. 688 at P 103. The Day 1 market is operated by the Southwest Power Pool, Inc. (SPP). In Order No. 688, FERC also found that CAISO operated a Day 1 market, but later found that CAISO's market structure satisfied the "comparable" market criteria in 210(m)(1)(C). *Pacific Gas and Electric Co., et al.*, 135 FERC ¶ 61,234 (2011) (finding the CAISO market to be a comparable market under Section 210(m)(1)(C))

[89] California Independent System Operator Corp. (CAISO) and Electric Reliability Council of Texas (ERCOT); *see Pacific Gas and Electric Co., et al.*, 135 FERC ¶ 61,234 (2011).

[90] Order No. 688-A at P 96.

the presence of transmission congestion can support a finding that QFs (of any size) do not have nondiscriminatory access to certain markets.[91]

In applying Order No. 688, FERC has broadly terminated the large QF mandatory purchase obligation for utilities operating in organized "Day 2" markets,[92] Southwest Power Pool's (SPP's) "Day 1" market,[93] and California Independent System Operator's (CAISO) comparable market.[94] In the lone large QF case to date where a utility termination request has been denied, FERC found that transmission system constraints impact the scope and geographic reach of the market a potentially affected QF may reach as an alternative to selling to the local utility.[95]

With limited exceptions, FERC has denied relief from the mandatory purchase obligation with respect to small QFs interconnected to utilities in Day 1 and Day 2 markets.[96] Two utility members of ISO-NE successfully rebutted the small QF no-access presumption for two particular small QFs on their systems, one for a 16 MW biomass facility and the other for 7.4 MW hydro facility,[97] but these cases appear to be exceptions. For example, FERC denied a request for a utility in ISO-NE to terminate the obligation for QFs between 5-20 MW because the applicant utility did not make a facility-specific showing of access.[98]

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[91] *Id* at P 115.

[92] *See, e.g., Duke Energy Shared Services, Inc.*, 119 FERC ¶ 61,146 (2007); *American Elec. Power Serv. Corp.*, 120 FERC ¶ 61,052 (2007); *PECO Energy Co.*, 122 FERC ¶ 61,022 (2008); *Alliant Energy Corp. Serv. Inc.*, 123 FERC ¶ 61,155 (2008); *The United Illuminating Co.*, 123 FERC ¶ 61,269 (2008); *Virginia Electric and Power Co.*, 124 FERC ¶ 61,045 (2008); *Allegheny Power*, 124 FERC ¶ 61,236 (2008).

[93] *Xcel Energy Services, Inc., et al.*, 122 FERC ¶ 61,048, *order denying reh'g*, 124 FERC ¶ 61,073 (order granting termination of purchase obligation in SPP for two utilities, but denying termination with respect to a third utility (SPS) because protesting QFs had provided sufficient evidence of operational constraints on SPS's transmission system to rebut the presumption that QFs have non-discriminatory access to the SPP market.).

[94] *Pacific Gas and Electric Co., et al.*, 135 FERC ¶ 61,234 (2011)

[95] *Xcel Energy Services, Inc., et al., reh'g denied*, 124 FERC ¶ 61,073 at PP 17-19 (2008).

[96] *See, e.g., PPL Electric Utilities Corp.*, 145 FERC ¶ 61,053 (2013), denying application to terminate obligation for an 18.1 MW QF in PJM region. FERC found that PPL had not provided sufficient evidence to show that market rules permit small QF participation in markets and that there are no constraints or other barriers to QF's output reaching the market, or that other QFs have participated in the markets. Commissioners Clark and Moeller, in a dissenting opinion, suggested that the Commission should provide more guidance to applicants on how they can be relieved of the PURPA obligation so as not to render meaningless the opportunity to rebut the presumption of no access for small QFs.

[97] *Fitchburg Gas and Electric Light Co.*, 146 FERC ¶ 61,186 (2014) (order granting application to terminate mandatory purchase obligation for a 16 MW QF located in the ISO-NE region); *City of Burlington, Vermont*, 145 FERC ¶ 61,121 (2013) (order granting application to terminate the mandatory purchase obligation for a 7.4 MW hydro facility that was connected directly to the ISO-NE grid).

[98] *Pub. Service Co. New Hampshire*, 131 FERC ¶ 61,027 (2010) (QM10-4) (order denying PSNH's request to terminate the mandatory obligation for QFs of 5-20 MW in size because PSNH did not make a facility-specific showing that each small QF had non-discriminatory access to the market).

Additionally, FERC has thus far not terminated the mandatory purchase obligation for any utility operating outside an organized market and, other than Electric Reliability Council of Texas (ERCOT) and CAISO, has not found any "comparable markets" to exist. Only utilities that have transferred control over their transmission systems to an ISO/RTO have satisfied FERC's market structure termination criteria.[99] While FERC has continued to encourage utilities to join ISO/RTOs, participation remains voluntary.

Congress did not intend that EPAct's provisions for relief from the mandatory purchase obligation apply only to utilities that have joined an ISO/RTO. Utilities that have not joined an ISO/RTO have little or no ability to obtain relief from the mandatory purchase obligation for either large or small QFs. Thus, there has been no relief from the mandatory purchase obligation for utilities that have determined that joining an ISO/RTO is not in the best interest of its customers. In addition, even for utilities that are members of an ISO/RTO, EPAct's benefits thus far have been arbitrarily limited to QFs greater than 20 MW, without consideration of the harm such QFs can cause. [100]

Most recently, FERC denied a Midwest utility's request to terminate the mandatory purchase obligation for a 17.92 MW QF despite finding that the QF had been selling into the MISO wholesale energy market since 2008.[101] Consistent with Order No. 688-A, FERC found that despite the QF's undisputed ability to sell into the MISO energy

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[99] *Public Service Company of New Mexico*, 139 FERC ¶ 61,128 (2012) (QM12-2) (order denying application to terminate purchase obligation under Section 210m (1)(C)). PNM argued that although no organized market existed, QFs had access to (1) a trading hub that flows into load centers, (2) the transmission hub is an intersection of balancing authorities, (3) Four Corners Hub is a relatively liquid market for the purchase and sale of power, and (4) the Four Corners provides opportunities to sell into part of the CAISO market. FERC held that, even if accepted entirely, the access PNM described does not provide sufficient evidence of access to a market of comparable competitive quality to Day 1 markets as provided in 210(m)(1)(B). Lack of an RTO/ISO for the area was a key factor in FERC's denial of the application.

[100] Ironically, in issuing Order No. 688, FERC recognized the problems facing utilities that prompted Congress to pass EPAct 2005:

> 24. Since Congress enacted PURPA, electric utilities have complained that their requirement to purchase from and sell to QFs, as implemented by the Commission in 18 C.F.R § 292.303(a)-(b), was not economically beneficial and that they were purchasing energy they did not need and selling energy they did not want to sell. In 1995, the Commission clarified that determinations of the avoided-cost rate must take into account all alternative sources including third-party suppliers and an electric utility does not pay for electric energy it does not need. In the past decade, with the development of exempt wholesale generators (EWGs) introduced by the Energy Policy Act of 1992, the implementation of open access transmission via Order No. 888, the advent of ISOs and RTOs and organized markets, the Commission's new interconnection requirements, and increasing competition in wholesale electric markets as well as some retail electric markets, Congress has debated whether to repeal PURPA altogether, or to revise it. The result is new section 210(m), which is the subject of this rulemaking, and new section 210(n), which was addressed in Docket No. RM05-36-000.

Order No. 688 at P 24. (citations omitted). Yet, FERC's policies have not been in line with Congress' goals.

[101] *Northern States Power Co.*, 151 FERC ¶ 61,110 (2015).

markets, the QF in question lacked the requisite nondiscriminatory access to the MISO *capacity* market because of transmission constraints on the MISO system that directly impacted the QF's ability to access the MISO capacity market.[102] The assertion that transmission upgrades were needed before the QF could sell into the MISO capacity market was sufficient for FERC to deny the termination request even though FERC found that the QF had the ability to pay for such upgrades, just like any other generator larger or smaller than 20 MW. In so doing, FERC effectively ruled that a 17.92 MW QF should not have to pay for the same transmission upgrades as would a 21 MW QF found to have nondiscriminatory access to the same market. This distinction between facilities of such a limited difference in size ties back to FERC's arbitrary 20-MW size demarcation in Order No. 688. The decision also continues a pattern of FERC rulings dating back to Order No. 688-A where the agency has effectively ruled that transmission system constraints constitute discrimination. In the eyes of many, FERC continues to misapply the PURPA 210(m) statutory termination standard in deciding whether to grant termination requests – whether QFs (regardless of size) have nondiscriminatory access to certain markets.

B. FERC's One-Mile QF Size Calculation Rule Has Resulted in Designation of Multiple Portions of Larger Energy Projects as Individual Small QFs Contrary to Congress' Intent Behind PURPA.

Under 18 C.F.R. § 292.204, to be certified a QF, a small power production facility may not exceed 80 MW total output. A facility is defined as any "facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, ***and*** are located at the same site."[103] The "same site" is defined as facilities that are "located within one mile of the facility for which qualification is sought" as measured from the electrical generating equipment.[104] FERC can modify or waive any of these requirements if "good cause" is shown.[105] QF size calculations are also relevant for regulatory exemptions available under 18 C.F.R. § 292.601 and 602, such as exemption from certain FPA approval requirements for small power QFs that are 30 MW or less and FERC rate filing requirements for QFs that are 20 MW or less.

Soon after the one-mile rule was promulgated, a wind farm sought a waiver from aggregating three facilities within one mile of one another. In *Windfarms, Ltd. Small Power Prod. & Cogeneration Facilities-Qualifying Status*, the total power generated

[102] *Id at P34-36.*

[103] 18 C.F.R. § 292.204 (emphasis added).

[104] *Id.* Transmission lines that connect the sites do not count for the purpose of calculating the one mile. *see N. Laramie Range Alliance Pioneer Wind Park 1, LLC Pioneer Wind Park II, LLC*, 139 FERC ¶ 61190 (June 8, 2012) ("While other equipment, such as transmission lines and other equipment, including equipment used for interconnection purposes, may be part of a QF certification, they are not electrical generating equipment.").

[105] 18 C.F.R. § 292.204.

from all three sites was under 80 MW, and thus qualified the site as a QF.[106] However, Windfarms wanted to be exempt from regulations under FPA, PUHCA, and state regulations.[107] At the time, in order to qualify for the exemption, a site could produce no more than 30 MW. Therefore, Windfarms divided the project into three areas and claimed they were distinct sites.[108] FERC granted the waiver in part because, although the facilities were within one mile of one another, the three areas were separated on distinct ridges of a mountain. FERC reasoned that "it is fundamental to the concept of the 'site' of a facility that the area where the facility is located is in some manner distinct from the surrounding area."[109] FERC found the mountain ridges to be distinct. Thus a "distinct surroundings" can overcome the one-mile requirement of the rule.

In 2012, *Northern Laramie Range Alliance* challenged the status of two wind parks. FERC certified the wind parks as two separate QFs because although the parks used the same energy source (wind) and were owned by the same person, they were more than one mile apart.[110] Northern argued that the one-mile rule only created a rebuttable presumption that the facilities were two separate sites. Northern further contended that the presumption could be overcome by showing the two facilities were "gaming"—acting as one site some times, but as separate sites at other times.[111] FERC flatly refused this interpretation of the rule stating "[t]here is certainly no language in that rule that suggests . . . that it is merely a rebuttable presumption."[112]

In short, according to FERC, a facility can be certified as a QF if the combined output of all generating sites owned by the same company within one mile exceeds the size limit as long as facilities can be broken up in some way so that "the area where the facility is located is in some manner distinct from the surrounding area."[113] Conversely, a site will not be denied QF status even if a party alleges that a company is "gaming" the cap by spreading small power production facilities more than a mile apart simply to beat the 80 MW cap on total production.[114]

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[106] *Windfarms, Ltd. Small Power Prod. & Cogeneration Facilities-Qualifying Status*, 13 FERC ¶ 61017 (Oct. 3, 1980).

[107] *Id.*

[108] *Id.* (noting the wind turbines were "clustered around the tops of three ridges in order to take advantage of the accelerating . . . effect of the windward slope of each site.").

[109] *Id.*

[110] *N. Laramie Range Alliance Pioneer Wind Park I, LLC Pioneer Wind Park II, LLC*, 139 FERC ¶ 61190 (June 8, 2012).

[111] *Id.*

[112] *Id.* (stating "the Commission's regulations was not intended to establish and did not establish merely a rebuttable presumption.").

[113] *Windfarms, Ltd. Small Power Prod. & Cogeneration Facilities-Qualifying Status*, 13 FERC ¶ 61,017 (Oct. 3, 1980).

[114] *N. Laramie Range Alliance Pioneer Wind Park I, LLC Pioneer Wind Park II, LLC*, 139 FERC ¶ 61190 (June 8, 2012).

As discussed above, under the rules promulgated by FERC, a utility is obligated to pay the full avoided costs of energy offered for sale by QFs, but a state has the authority to reduce the price if it is in the public interest while still encouraging growth of QFs.[115] Under these rules, a state must put into effect standard mandatory payment rates for QFs that generate 100 kWs of power or less, and may put into effect a standard rate for QFs that produce more than 100 kWs.[116] Prior to December 2010, Idaho's Public Utility Commission (IPUC) required payment of published avoided costs to QFs generating 10 MW or less, thus going beyond the 100 kW requirement.[117] QFs that produce in excess of the 10 MW limit are required to negotiate a rate with the utility based on Idaho's Integrated Resource Plan (IRP) Methodology.[118] This methodology takes into account "when the QF is capable of delivering its resources against when the utility is most in need of such resources."[119] It does not relieve the utility of the obligation to buy, but rather the IRP price "is reflective of the value of the QF energy to the utility."[120]

In November 2010, Idaho Power Company, Avista Corporation, and Rocky Mountain Power (Idaho Petitioners) submitted a joint petition to the IPUC requesting an investigation into issues regarding IPUC's implementation of PURPA including avoided rates. The Idaho Petitioners stated that "many of the current QF projects in actuality are not 'small' projects but are large, utility-scale wind farms that are broken up into [smaller] increments in order to qualify for the published rates."[121] The Idaho Petitioners requested injunctive relief to reduce the cap on mandatory payment of published rates to those QFs that produce less than 100 kWs while the investigation was under way.[122] IPUC initiated the investigation and temporarily granted the petitioners' motion to reduce the eligibility cap for published rates as of December 14, 2010.[123]

In 2013, FERC filed a lawsuit in federal district court against the IPUC, its first against a state public utility commission to enforce sections of PURPA.[124] While FERC's case centered around when an obligation to purchase comes into effect under PURPA, the key issue lies in the 2010 petition filed with IPUC by local utilities wherein they alleged that many large projects are being broken up into smaller ones to qualify for the published rates.

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[115] 18 C.F.R. § 292.304(b).

[116] 18 C.F.R. § 292.304(c).

[117] Idaho Public Utilities Commission, Order No. 32176, 1 (March 2011).

[118] *Id.*

[119] Idaho Public Utilities Commission, Order No. 32255, 2 (June 2011).

[120] *Id.*

[121] Petitioners Motion, Idaho Public Utilities Commission, Case No. GNR-E-10-04, 6 (November 2010).

[122] *Id.*

[123] Idaho Public Utilities Commission, Order No. 32176, 1-2 (March 2011).

[124] Complaint, *F.E.R.C. v. Idaho Public Utilities Commission*, No. 1:13-cv-141 (D. Idaho 2013).

At issue in FERC's lawsuit against IPUC was the IPUC's refusal to accept power purchase agreements (PPAs) entered into by utility companies and multiple QFs who produced between 100 kWs and 10 MW that were signed after the IPUC reduced the mandatory payment cap on published avoided rates on December 14, 2010.[125] The lawsuit boiled down to a basic dispute. On the one hand, IPUC drew a "bright line rule" refusing all contracts that were not "executed" (*i.e.*, signed by both parties) before December 14, thus requiring the parties to negotiate an IRP price. FERC, on the other hand, argued that a "legally enforceable obligation" can be formed before the contract was executed. Ultimately, the lawsuit raises a larger policy question of whether QF applicants are breaking large projects into smaller pieces to qualify for the mandatory purchase benefits and more advantageous price structures, and whether that comports with the Congressional intent of PURPA.

It is clear from the legislative history and subsequent amendments to Section 210 of PURPA that Congress intended to limit Section 210 to "small" (80 MW or less) renewable power production facilities. Congress exempted larger facilities with an amendment in 1990 but that size exemption only applies to facilities qualified or under construction before 2000. This size exemption does not apply to new facilities. Congress amended Section 210 since then (2005) and did not change the size restriction of small renewable projects otherwise qualifying for QF status. Thus, it is clear Congress did not intend for FERC to expand the size of renewable QFs to any facility that has the capacity to exceed 80 MW using the same resource, owned by the same person, and located at the same site.

FERC's "one-mile" rule has been in effect since FERC promulgated the initial rule implementing the provision in 1980.[126] As early as 1987 utility companies in multiple states were complaining to FERC about being "forced to accept capacity that they did not need because avoided costs rates based on long-term projections . . . were sufficient to spur significant QF development."[127] Decades later, the Idaho Petitioners faced similar problems. In some markets such as Idaho Power's, if all of the wind energy under QF contracts comes online, it alone will exceed any other single source of generation – hydro, coal, natural gas or other renewables – that exists on Idaho Power's system. While this rule has been in place for several decades, FERC has interpreted its own rule to allow distinct projects within one mile to qualify and recently, in the *Northern Laramie Range Alliance* order, has ruled that the one-mile rule is a standard FERC cannot ignore allowing QF status of facilities 2.5 miles apart even though operating as a single unit and designed to get beyond the one-mile limit. Thus, it appears FERC exercises broad discretion in determining what QF is "located at the same site."

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[125] *Id.* at 2 FERC and the IPUC agreed to dismiss the pending district court litigation in a settlement, in which IPUC "acknowledges that a legally enforceable obligation may be incurred prior to the formal memorialization of a contract to writing." Memorandum of Agreement Between the Federal Energy Regulatory Commission and the Idaho Public Utilities Commission, dated Dec. 24, 2013.

[126] 18 C.F.R. § 292.204.

[127] *See* GRAVES *supra* note 31, at 16.

At present, developers are taking advantage of the one-mile rule and incorporating that opportunity into their development plans to game the PURPA rules to their advantage. For example, a northwest utility reports that in Wyoming and Idaho it has 32 existing QF projects that are taking advantage of the one-mile rule by locating separate segments of their projects slightly more than one mile from each other.[128] Thus, a single developer can effectively exceed the size limitations for small power production facilities contrary to Congress' intent. The same phenomenon is occurring in Utah with respect to solar facilities. Left unchecked, developers can impose significant costs on utility consumers by exceeding the statutory and regulatory size limitations.[129] To limit any gaming opportunities, FERC should instead adopt a rebuttable presumption that facilities located more than a mile apart are independent projects, but a utility or other interested party should be able to rebut that presumption by showing that two or more facilities are part of a common enterprise.[130]

C. With the Implementation of Open Access Transmission and Interconnection Service, QFs Can Choose to Sell Outside Their Interconnected Utility's Service Area to Take Advantage of More Favorable Price Structures in Neighboring States Regardless of Whether the Power is Needed.

FERC's Order Nos. 2003[131] and 2006[132] establish standard procedures and a standard interconnection agreement for large (>20 MW) and small generators, respectively. FERC has also implemented standard agreements for wind energy and other alternative technologies for their interconnection to the grid.[133] As a result,

[128] PacifiCorp reports that it currently has 3,641 MW of new PURPA contracts in addition to the 1,732 MW of PURPA contracts already executed. This equates to enough capacity to supply 79% of the company's average retail load and 108% of the minimum retail load.

[129] PacifiCorp reports that over the next 10 years it is under contract to purchase from QFs at an average price that is 43% higher than current market prices.

[130] Comments of the Edison Electric Institute, Docket RM09-23-000, dated Dec. 22, 2009.

[131] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004) (Order No. 2003-A), *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2005) (Order No. 2003-B); *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005); *see also* Notice Clarifying Compliance Procedures, 106 FERC ¶ 61,009 (2004).

[132] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 FR 34100 (Jun. 13, 2005), FERC Stats. & Regs. ¶ 31,180 (2005) (Order No. 2006), *order on reh'g*, Order No. 2006-A, 70 FR 71760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005), *order on clarification*, Order No. 2006-B, 116 FERC ¶ 61,046 (2006). .

[133] Interconnection for Wind Energy, Order No. 661, 70 FR 34993 (June 16, 2005), FERC Stats. & Regs. ¶ 31,186 (2005) (Final Rule); *see also* Order Granting Extension of Effective Date and Extending Compliance Date, 70 FR 47093 (Aug. 12, 2005), 112 FERC ¶ 61,173 (2005); *order on reh'g and clarification*, Order No. 661-A. According to FERC, "The rule addresses concerns of wind turbine manufacturers and wind power developers who sought standardized interconnection requirements. Having to meet widely varying standards across the country contributes to increased manufacturing costs for wind

interconnection issues for wholesale power producers are no longer barriers to entry, which was one of the concerns behind the need for PURPA when it was first enacted. Once interconnected, a QF can choose to sell its output to any utility to which it can deliver firm power and that utility is required to purchase it. QFs can thus engage in price shopping and sell to more distant utilities if the price structure is more advantageous, regardless of whether the power is needed.

In a recent declaratory order directed to the Oregon Public Utilities Commission, FERC found that a QF has the discretion to choose to sell to a more distant utility as long as the QF can deliver its power to the utility.[134] Kootenai Electric Cooperative's Fighting Creek QF (Kootenai), a 3 MW net capacity landfill gas plant located in Idaho, sought to sell its output across Avista Corporation's system to Idaho Power Company's facility in Oregon in order to take advantage of Oregon's more favorable rates and terms.[135] In requiring the Oregon Utilities Commission to approve the agreement if Kootenai met the terms of service, FERC held that a utility is obligated under PURPA to purchase the output of a QF as long as the QF can deliver its power to the utility – even if the state PUC seeks to limit such access to its PURPA rates.[136]

D. FERC's One MW Administrative Exemption to the Self-Certification Filing Requirements is Overly Broad and Should be Lowered to 100 kW.

FERC's Order No. 732, issued in 2010, implemented rules to simplify procedures for obtaining QF status for those small entities (one MW or less) that may consider the administrative process burdensome or that, according to FERC, may lack access to the computer facilities necessary to make an electronic filing. FERC stated that it chose the one MW threshold because facilities larger than that represent a significant departure from residential, retail, hospital and school power generation and thus can be expected to have the ability to file a Form No. 556.[137] As a result, any QF of one MW or less does not need to file a self-certification (Form No. 556) in order to meet QF requirements.[138]

Although FERC stated in the proposed rule that residential, retail, hospital and school power generation was a focus of the administrative relief for small generating units, a one MW facility is too large for such uses and thus the exemption affects QFs of significantly large commercial size as well.[139] According to EEI, on site residential power

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generators and serves as a barrier to development of this renewable resource." FERC Press Release, Docket No. RM05-4, May 25, 2005.

[134] *Kootenai Elec. Coop., Inc.*, 143 FERC ¶ 61,232 (2013).

[135] *Id.*

[136] *Id.*

[137] Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility, Order No. 732, 103 FERC ¶ 61,214 at 35 (2010).

[138] 18 C.F.R. § 292.203(d).

[139] Order No. 732 at P 35.

generation such as solar panels are typically in the 5 kW size range. Even many generation sources at industrial and large commercial locations are smaller than one MW.[140] According to Solar Energy Institute Association, the average residential photovoltaic system price is just below $5.00 W and the average non-residential system price is just below $4.00/W. This equates to a total installed cost of nearly $5 million for a one MW residential project and $500,000 for a 100 kW project.[141] These figures are far too high for the typical residential unit. Moreover, any party investing millions in a QF facility of the size of one MW is not the kind of party that lacks adequate computer facilities to file a Form No. 556.

Utilities and state commissions should have appropriate regulatory processes in place to verify the QF status of generating facilities that affect consumer rates. With FERC's one MW or less exemption, many commercial QFs are exempt from regulatory processes. A far more reasonable figure for the self-certification exemption would be 100 kW, which would still be more than large enough for residential units and would coincide with the 100 kW threshold for FERC's existing PURPA regulations, which require electric utilities to establish standard rates for purchases from QF with a design capacity of 100 kW or less. FERC's self-certification filings provide utilities and state commissions with important technical and design information that they need to determine likely system impacts and interconnection designs. Exempting projects greater than 100 kW, deprives utilities and state commissions of valuable information for system operations.

E. PURPA Contracts are Not Subject to the Same Planning and Cost Scrutiny as Other Resource Decisions and thus Expose Customers to Increased Cost and Unnecessary Risks.

Many utilities, as required by state commissions, utilize an integrated resource planning process (IRP) to evaluate proposed energy contracts to ensure that any resource decisions are reasonable and prudent. The planning horizon for such resource plans typically is in the three-year range. PacifiCorp, for example, primarily enters into long-term transactions (those that exceed 36 months) only when there is a clearly identified long-term resource need in its IRP. Companies also utilize a rigorous request for proposal RFP process to acquire any long-term transaction or resource need identified in the IRP.

Under PURPA, however, companies cannot refuse to execute PURPA contracts based on the price or the contract term, or whether the energy is needed, or based on other transaction parameters that would normally be the basis for rejection of other RFP contracts.

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[140] Comments of the Edison Electric Institute, filed in response to FERC Notice of Proposed Rulemaking, Docket No. RM09-23-000 at 8.

[141] *U.S. Solar Market Insight 2013 Q1*, SOLAR ENERGY INSTITUTE ASSOCIATION, (March 26, 2015), http://www.seia.org/research-resources/us-solar-market-insight-2013-q1.

PURPA contracts do not go through the same competitive bid RFP process including oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP. PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation under federal law. As a result, PURPA contracts expose customers to increased cost and unnecessary risks with no resulting benefits.

VI. Conclusion

PURPA has out served its usefulness and it is now imposing significant and unnecessary costs on consumers by requiring utilities to purchase unneeded power at above market prices. Because utilities and state commissions have little ability to refuse the power, PURPA contracts do not go through the normal competitive bid process as other supply contracts do. Utilities cannot refuse to execute PURPA contracts based on price, contract term or whether the energy is needed – regular considerations for prudent energy purchases outside the PURPA context. Such inefficient resource acquisition requirements are no longer needed to encourage independent power production given the significant energy industry structural changes imposed by FERC that have occurred since PURPA was enacted in 1978.

U.S. Senate Committee on Energy and Natural Resources
May 14, 2015 Hearing: Energy Infrastructure Legislation
Questions for the Record Submitted to Ms. Amy Ericson

Questions from Chairman Lisa Murkowski

Question 1: What are the lessons learned from Smart Grid demonstration projects and technology investments?

There are multiple lessons learned over the last few years; public-private partnerships are a very effective way of driving innovation, field testing and workforce training. Smart Grid pilots have also allowed utilities and industry to increase understanding of the benefits and challenges of deploying new technologies, including enhancing distribution grid operations for the adoption of Distributed Energy Resources (DER) and the reliable integration of large-scale remote renewable energy. Other smart grid projects are focused on hardening and resiliency of the power grid. Demonstration programs have also provided significant knowledge and understanding of region specific issues that are important to implementation of Smart Grid technologies.

It is important to note that the grid is truly essential and a foundation of our Nation's economy and society. Therefore, technology must be proven at pilot and demonstration scale before commercial deployment.

Question 2: Can energy storage be priced effectively as a generation resource? If so, please explain how.

Energy storage technologies include hydro pumped storage, compressed air energy storage, thermal storage on solar plants and battery storage. Storage plays an important role from bulk storage, to time of day load shifting, to power quality balancing.

Battery based energy storage costs are expected to continue to fall with improvements in manufacturing processes and economies of scale, as we have seen with other technologies. The next generation of battery energy storage is at the stage to be deployed for large scale field demonstration. To reiterate our response to the previous question, pilot projects are critical to proving the reliability, effectiveness and economic viability of the technology.

When paired with traditional or renewable generation, including DER, energy storage can play a critical role in providing flexibility for energy balancing, ancillary services and resiliency. Energy storage technologies should be allowed to compete to service these performance needs of the system on an open basis. Policy should focus on the cost and capability and not define specific technologies as winners before the race.

Question 3: Do you agree that utility-scale renewables are cheaper, easier to integrate onto the grid, and provide far more economies of scale than residential-scale distributed generation?

a. What is needed to encourage utility-scale renewables?

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b. What infrastructure obstacles are reduced or avoided by focusing more on utility-scale renewable generation?

Yes, today there are economies of scale for the capital costs and maintenance costs of larger-scale renewables, including wind, geothermal, hydropower and solar. Also, with the exception of solar, these renewable resources are often remote from load centers, where siting, construction and maintenance can be optimized by a larger scale facility.

This does not negate the value of local distributed renewable generation; rather it is our belief that both technology pathways will be absolutely necessary to achieve any significant increase in renewable energy use. It is important that the transition to renewable energy include a portfolio of resources which can produce energy at different times of the day/year creating a better balance between demand and supply. For example, geothermal power is 24/7 dispatchable, wind resources often tend to be strongest in late afternoon, large scale solar produces highest at mid-day, but can integrate thermal storage to extend the hours of production; each has unique benefits. Also, hydropower pumped storage is the single largest energy storage technology commercially available and is capable of storing all other forms of renewable energy and supplying that energy on demand.

Utility scale renewables must continue to play an important role in a transition to clean energy. However, siting and access to transmission present challenges. Consistent and predictable incentive policies (e.g., the Production Tax Credit (PTC) for wind and hydro, the Investment Tax Credit (ITC) for solar and offshore wind, etc.), and harmonizing and streamlining federal and state regulations on permitting and planning transmission will help the adoption of utility scale renewables.

Question 4: Can you explain why renewables such as solar and wind need the grid to operate? What services specifically does the grid provide to consumers who are producing their own electricity?

Consumers will not be able to meet their demand all the time, even with oversized solar and wind on their property. Solar will generate less energy in winter months and will over generate in summer months. Solar and wind are complex to forecast and driven by local weather patterns. To address this, a grid is required for consumers to continue to receive electricity during times of higher demand. The grid also provides a back-up for consumers when solar and wind generation is not available.

The typical and most cost-effective rooftop solar system today is without battery storage. This solar panel system truly needs the grid to balance the supply from the solar panels with the usage by appliances in the home. Without the grid, such as during an outage, these solar panel systems must shut down to avoid power fluctuations, high or low, and potential damages to the home appliances.

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Question 5: Are you concerned the distributed generation has resulted in improper cost shifting for consumers? Does net metering account for the value of ancillary services provided by the grid?

Question from Senator Maria Cantwell

Question: What are the best workforce training models Alstom has witnessed or participated in to address what is really a generational turnover in the electric power sector's workforce?

Attracting and retaining talent in the electric power industry is a major challenge for electric utilities, vendors/manufacturers and universities. Partnering with utilities and universities to train and retain talent is a major focus for Alstom. We continue to participate in joint research and development with universities throughout the United States, and through a summer internship program we are able to attract future engineers into Alstom. Providing engineers with opportunities to grow their career including post-graduate education is critical in retaining our engineers. Alstom has also partnered with our customers and their local universities, helping train future engineers by donating our software to these universities for teaching and R&D. Alstom encourages all our engineers to actively participate and volunteer in the IEEE Power and Energy Society (PES) to continue their education and train the next generation of engineers.

Smart grid jobs will require leaders who can think about several aspects of an electric energy industry company. Recently, in a panel of utility CEOS, they defined their need as 'a cross discipline engineer with electrical, IT and telecommunications expertise'. We work with multiple universities across the country donating simulators and working on joint research. At a technical training level, community colleges excel at developing training programs and full courses to quickly accommodate workers who need to retrain while maintaining full-time jobs at technology companies and utilities. An effective model includes programs such as the 52 Smart Grid workforce training programs in 32 states and the District of Columbia which were funded by Department of Energy (DOE) under the Recovery Act. These programs will train approximately 30,000 U.S. workers in smart grid technologies.

Questions from Senator Ron Wyden

Question 1: In your opinion, what are the top three things that could be done to expand capacity and ancillary services markets to include resources such as energy efficiency, distributed generation and demand response?

EE/DG/DR are eligible to participate in capacity and ancillary services in the wholesale electricity markets, but the level of participation is small in comparison to conventional resources. To foster growth in EE/DG/DR, it is important to focus not only on wholesale

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markets but also at the retail/distribution system level. EE/DG/DR can provide multiple functions (services) at the local distribution system and be compensated fairly and reasonably. To promote growth in EE/DG/DR a number of smart grid technology enablers must be demonstrated at pilot scale to ensure continued reliability and economic viability.

Question 2: I would like to make sure that as we develop the grid infrastructure of the future, we continue to protect the privacy rights of American citizens. Can you talk about some of the key ways in which we can hit the sweet spot of both tapping the potential of the smart grid while protecting privacy?

Consumer privacy is imperative in building out the smart grid. The electric industry must provide consumers with choices on what data is shared and how it is shared. Consumers should have access to their own electricity usage and data collected through smart meters, and the right to share this data with certified 3rd parties. Consumer education is another key area for lessons learned from the initial smart grid pilots, including the benefits of adopting emerging smart grid technologies.

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Questions from Chairman Lisa Murkowski

Question 1: You testified that some states have been "tempted by short-sighted arguments" to undermine the modernization of the nation's collective grid system. In his testimony, Commissioner Kalk urged the Committee "to always be mindful of the impact of cost and reliability." Do you agree with the state commissioner that reliability and consumer costs are necessary factors to consider? If not, why not?

The Quadrennial Energy Review, or QER, found that historically, the leading threat to electric grid reliability has been weather-related, and unmitigated climate change is expected to increase frequency and severity of extreme weather events. However, through proactive investments in resilience, utilities can protect their investors and ratepayers against excessive recovery costs in the wake of natural disasters. The QER cited a study that found approximately $135 billion worth of damages to energy facilities along the Gulf coast could be avoided by investing $50 billion in resilience retrofits over the next 20 years.[1] Similarly, higher temperatures associated with climate change threaten to inhibit cooling operations for many thermoelectric power plants around the country and undermine grid operations at the very moment increased electricity for cooling is most needed. Researchers at Arizona State University found that power plants in the Western United States risk losing 3%-8.8% capacity due to extreme heat caused by climate change.[2]

Additionally, many new technologies that provide ancillary benefits to grid operations can enhance grid reliability at lower costs than traditional capital intensive projects. By using technologies that can moderate fluctuations in voltage and frequency or offset grid strain at times of peak demand, utilities can avoid investment in major capital projects.

Question 2: You take issue with my PURPA provision (S. 1219) to direct states to ensure the safe and reliable interconnection of distributed resources and to consider whether net metering rates are just and reasonable for all consumers. According to testimony from Berkshire Hathaway, net metering is resulting in cost-shifting because the grid-related charges are not captured. Both Berkshire Hathaway and EPRI (who testified at the Committee's March 17 grid hearing) say that distributed generation systems cannot function without the grid. Are they wrong?

a. If so, please explain how these "dg" systems operate as separate micro-grids.
b. Does net metering account for the value of ancillary services provided by the grid?
c. If not, why should customers without rooftop solar panels subsidize those that can afford to put solar on their homes?

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[1] Greg Dotson and Ben Bovarnick, "A Forward-Looking Agenda for the Nation's Public Utility Commissions" (Washington: Center for American Progress, 2015) available at https://cdn.americanprogress.org/wp-content/uploads/2015/05/PURPA-report-final.pdf

[2] Herman K. Trabish, "How climate change threatens the Western grid, and what to do about it" *Utility Dive,* May 29, 2015, available at http://www.utilitydive.com/news/how-climate-change-threatens-the-western-grid-and-what-to-do-about-it/399935/

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Many distributed generation systems are designed to function most efficiently through interconnection with the grid. Although the majority of energy produced by many DG systems is used at the point of generation (i.e. a home or business), building demand does not always match the generation levels of a DG system.

Interconnection and net metering programs provide opportunities for DG systems to contribute energy to the electric grid, particularly at times of peak demand in the case of solar power. Through net metering provisions, states have protected the rights of homeowners and businesses to receive compensation for the contributions their systems provide to the electric grid. A study commissioned by the Mississippi Public Service Commission to evaluate net metering in Mississippi – which does not currently require net metering – found that a statewide net metering program would yield net financial benefits to the state and its citizens. These benefits include avoided utility costs, such as deferred investment in additional generation, transmission, and distribution assets, and increased grid resilience.[3] Furthermore, reducing generation from polluting fossil fuels avoids health-related costs imposed on all ratepayers and the costs to future generations from unmitigated climate change.

Question 3: What are the lessons learned from Smart Grid demonstration projects and technology investments?

In November 2009, Secretary Chu awarded $620 million in ARRA funds "for projects around the country to demonstrate advanced Smart Grid technologies and integrated systems that will help build a smarter, more efficient, more resilient electrical grid." More than 30 demonstration projects were chosen, and the program was supplemented by $1 billion in private sector investment.[4]

The projects aimed to implement emerging smart grid technologies. Each varied in scale and scope, but all of them focused on increasing the efficiency of the grid. Many of these projects used smart metering, which allows utilities and customers to optimize renewable energy generation and energy savings while enhancing the reliability of the grid. The largest project, the Pacific Northwest Smart Grid Demonstration Project, focused on integrating many efficiency measures into the project and sharing best practices among the many different utilities. More information on the different projects and their successes can be found via DOE.[5]

Question 4: Transparency and "dashboards" are very popular now. OMB has developed an infrastructure permitting "dashboard" at the behest of the President to shine a light on

[3] Elizabeth A. Stanton and others, "Net Metering in Mississippi," (Massachusetts: Synapse Energy Economics, Inc., 2014) available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf
[4] Department of Energy, "Recovery Act SGDP," available at http://energy.gov/oe/services/technology-development/smart-grid/recovery-act-sgdp (last accessed May 2015).
[5] Ibid.

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both delays and progress. eTrans is another permitting dashboard resulting from an inter-agency MOU. However, not every project is posted to these public displays, and information is often incomplete or out-of-date.

a. Are these dashboards helpful?
b. Would greater use of them assist in the streamlining of the infrastructure permitting problem?
c. What changes need to be made to the dashboards (such as more information on the estimated timelines, or information on exactly how "delayed" as project is) to make them more useful?

The Center for American Progress has not previously written on infrastructure dashboards. However, we do support initiatives that enhance government transparency, including for infrastructure permitting.

Question 5: There appears to be consensus that the federal permitting process for transmission project must be improved. Do you agree? What can Congress do to bring some reasonableness and certainty to this byzantine process?

The Department of Energy's Quadrennial Energy Review (QER) examined this issue in detail, given rapidly changing energy infrastructure needs. The QER states: "The complexity and pace of the Federal permitting and review processes for proposed infrastructure projects has been identified as a key challenge to building U.S. infrastructure for transporting, transmitting, and delivering energy." The QER also notes that "it is essential to promote more timely permitting decisions while protecting our Nation's environmental, historic, and cultural resources."[6]

The QER offers several recommendations that Congress could adopt. Notably, the QER recommends that Congress allocate sufficient resources to the agencies tasked with processing federal permit applications. Agencies have experienced significant budget cuts in recent years; it is not reasonable to expect these agencies to review permits more quickly with less money and fewer staff.

Question 6: Until economically viable, commercial scale energy storage becomes available, what alternatives do we need to ensure continued grid integration and reliability?

Energy storage is being deployed today and the market is seeing the prices for storage decline. As the cost of clean energy technology continues to fall, regulators must be proactive in establishing standards for deployment that achieve economic, environmental, and other societal benefits, and that address any institutional biases against clean generation. Regulators will have to adopt better planning and prediction methods to accommodate clean energy in a way that ensures grid stability and reliability. Support for

[6] Department of Energy, "Quadrennial Energy Review," available at http://energy.gov/epsa/quadrennial-energy-review-qer (last accessed May 2015).

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deployment of new technologies such as smart inverters can enhance grid reliability by reducing voltage and frequency fluctuations for a fraction of overall system cost. Appropriate valuation of ancillary services will enhance grid stability and drive a market for energy storage, which will reduce the timeframe for commercial viability. Finally, continued improvement of predictive models to assess wind and solar electricity output will support grid efficiency and reliability.[7]

Question 7: Are wind turbines and solar photovoltaics mature power technologies?

The technologies for wind power and solar photovoltaic power are in the process of maturing but these technologies continue to face challenges in competing with established electricity generation technologies that rely on fossil fuels. Wind and solar are increasingly attractive options and provide the benefits of low carbon electricity. However, this benefit is still insufficiently valued in the marketplace.

In recent years wind and solar generating capacity have both grown, and are expected to increase in 2016, according to projections by the Energy Information Administration (EIA). Wind power is increasingly serving a large part of the U.S. power needs, and the comparative levelized cost (the cost that combines capital costs, costs of operations and maintenance, fuel, and performance)[8] of wind power declined 58 percent from 2009 to 2014.

Solar capacity is also growing as its cost declines. The levelized cost of utility-scale crystalline solar photovoltaics decreased 78 percent from 2009 to 2014, falling nearly 20 percent from 2013 to 2014 alone.[9]

With continued support for technological innovation and efforts to reduce the deployment costs of wind and solar power, these renewable power sources will become even more competitive with traditional carbon-intensive fuel sources.

Question 8: In your prepared testimony you state that "Regulators that consider the value offered by clean energy beyond their immediate benefits can better serve state consumers…"

a. Please explain what you mean by "beyond their immediate benefits" and provide specific examples.
b. How would you have regulators calculate these benefits and translate them into rates?
c. What sets this apart from a hidden tax imposed by regulators?

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[7] Dotson and Bovarnick, "A Forward-Looking Agenda."
[8] National Renewable Energy Laboratory, "Levelized Cost of Energy Calculator," available at http://www.nrel.gov/analysis/tech_lcoe.html (last accessed May 2015).
[9] Lazard, "Lazard's Levelized Cost of Energy Analysis—Version 8.0," (2014) available at http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

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As clean energy generation increasingly demonstrates cost competitiveness with traditional sources of electricity, it is important that regulators consider the benefits such generation can provide beyond the electricity generated. Historically, the value of electricity generation has been determined by the price of generation and reliability of centralized transmission. However, this valuation fails to account for the costs associated with pollution, the benefits of a resilient, decentralized grid structure, or the avoided costs of new transmission that distributed generation can provide. As noted in a recent Center for American Progress report, "Clean energy does not impose health risks on the communities they serve, can be placed closer to demand centers mitigating the need for additional investment in transmission, and with microgrids that can operative independently of the traditional electric grid, can provide access to electricity during blackouts."[10] Deployment of renewable energy can also be an important hedge against the prospect of increasing natural gas prices.

The DOE suggests that regulators consider the value of clean energy beyond the immediate benefits so that regulators can better serve their state consumers with "a portfolio of electricity options that meet their state specific goals for reliable, affordable, and clean electricity."[11] Regulators could calculate these benefits by assessing avoided costs of transmission and distribution upgrades, avoided costs of air pollution, and establishing metrics for increased reliability of distributed clean energy generation in the face of extreme weather. Regulators could also develop rate structures that value ancillary services provided by clean energy and energy storage technologies.

Question 9: You testified in support of S. 1213, the Free Market Energy Act of 2015. That bill introduces a new rate treatment concept called a "societal value of distributed energy resources." Please define the "societal value of distributed energy resources" and explain how you believe state utility commissions should treat it for ratemaking purposes.

How this term should be interpreted will best be determined by the author and the Committee. However, as discussed above, there are numerous benefits to society of distributed energy resources.

Question 10: Berkshire Hathaway testified that PURPA's mandatory purchase requirement has forced PacifiCorp to lock in contract rates over the next decade that are 43 percent higher than the market price – forcing customers to pay an incremental $1.1 billion for the next 10 years for electricity the company does not even need. Do you think this is a fair result? If so, please explain. If not, how do you propose amending the 1978 law?

PURPA has a well-established history of encouraging diversification of our nation's electric generation and driving investment into cogeneration facilities and renewable energy. In the 1980s to 1990s following the passage of PURPA, cogeneration and clean

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[10] Dotson and Bovarnick, "A Forward-Looking Agenda."
[11] Department of Energy, "Modernizing the Electric Grid." In *Quadrennial Energy Review*, (2015) available at http://energy.gov/sites/prod/files/2015/04/f22/QER_Ch3.pdf

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energy generation experienced significant expansion.[12] Although some utilities have stated that the qualifying facilities provision imposes billions of dollars in excess costs, CAP is unaware of publicly available documentation of excessive costs imposed on utilities. Some public assertions by utilities of excessive costs have been criticized for including projects not seriously proposed or ever implemented.[13]

Additionally, it's important to understand what an avoided-cost contract is. The contract prices set through avoided-cost calculations are equivalent to contracts that would have been negotiated by conventional utilities investing in new generation themselves. The contracts are designed to reflect the cost to consumers independent of generating source, and in the event of increases in fossil fuel prices, conventional utilities would have instead imposed even higher rates.[14]

Question 11: How can new technologies, such as superconductors, improve the nation's grid resiliency?

New technologies, particularly renewable energy technologies, can bolster the nation's grid resilience to extreme weather events and other impacts of climate change, as well as to terrorist attacks. For example, distributed generation, such as that from rooftop solar, has the potential to power homes or other community assets even after extreme weather events that damage centralized power lines and substations. For instance, a clean energy project at a school in Rutland, Vermont, will use solar panels and battery storage to provide power and ancillary services to the grid during normal operation, but in the event of a grid outage, it can serve as a powered emergency shelter.[15]

Other new technologies such as superconductors and smart meters can help moderate grid fluctuations. Superconductors have the potential to ensure the renewable grid can accommodate varying capacities because they are engineered to carry a higher electric load while lessening resistive losses. They are beneficial because they can better transmit the intermittent loads from renewable sources. Smart metering technology is already in use by many utilities, allowing them to respond to fluctuations in demand more efficiently and to stabilize the grid.

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[12] Joel Bluestein and Marie Lihn, "Historical Impacts and Future Trends in Industrial Cogeneration" (Gas Research Institute, 1999), available at http://aceee.org/files/proceedings/1999/data/papers/SS99_Panel1_Paper41.pdf

[13] Rocky Barker, "Risch bill would free Idaho Power from forced buy if it shows it doesn't need more power," Idaho Statesman, May 13, 2015, available at http://www.idahostatesman.com/2015/05/13/3801326_risch-bill-would-free-idaho-power.html?rh=1

[14] Union of Concerned Scientists, "Public Utility Regulatory Policy Act (PURPA)," available at http://www.ucsusa.org/clean_energy/smart-energy-solutions/strengthen-policy/public-utility-regulatory.html#.VR2CRCTD9ol (last accessed May 2015).

[15] Energy Manager Today website, "Vermont Microgrid Combines Solar, Storage") available at http://www.energymanagertoday.com/vermont-microgird-combines-solar-storage-0104037/) (last accessed May 2015).

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Additionally, distributed generation and battery storage assets can help prevent large-scale power outages by allowing the grid to draw power from many sources, rather than centralized power facilities. This decentralization helps to insulate the grid from failure in the event that energy transportation infrastructure or a power plant is severely hindered during extreme weather or another event.

Questions from Ranking Member Maria Cantwell

Question 1: Resilience is a concept that is attracting more attention with climate change-driven extreme weather disrupting our economy. We are more exposed than ever to big storms taking out crucial power plants or transformers. As you've looked across the country and thought about the grid of the future, what states or utilities have you seen get ahead of the curve in investing in resilience?

Power companies and states have implemented a variety of initiatives to make the electric grid more resilient. For example, Baltimore Gas & Electric (BGE) in Maryland installed 100,000 smart meters immediately prior to Superstorm Sandy in 2012. BGE was able to use these new meters to quickly identify where outages had occurred and to verify when problems were fixed. According to GreentechMedia, "within 48 hours, 90 percent of BGE's customers had their power restored. The utility calculated it had saved more than $1 million in labor costs by more efficiently deploying line workers and eliminating the need for 6,000 truck deployments." Pepco had a similar experience in responding to outages, thanks to their use of smart meter infrastructure, restoring power to 95 percent of customers within two days.[16]

PSE&G has $1 billion in planned investments to harden the grid as part of its post-Hurricane Sandy Energy Strong plan. These investments include: $100 million to create a program that will better detect faults and problems in the distribution system, $100 million to install remote controls for substations, and a distribution management system that combines customer, outage, and field data into one system.[17]

The Partnership for Energy Sector Climate Resilience is a voluntary partnership program between seventeen utilities and the Department of Energy to "work together to overcome existing technology and policy barriers to enhance energy sector resilience to climate change and extreme weather; to provide more user-friendly climate data and decision tools; to assess incentives and disincentives associated with regulations and policies; to assess cost and benefits of climate resilience actions; to identify metrics for measuring success in enhancing climate resilience and use them to assess progress; and to identify key gaps and opportunities related to the development and deployment of climate-resilient energy technologies, practices and policies." As of April 2015, member utilities

[16] Stephen Lacey, "From Smart to Resilient: How Utilities Are Using New Technology to Protect the Grid," In Greentech Media, ed., *Resiliency: How Superstorm Sandy Changed America's Grid* available at https://www.greentechmedia.com/articles/featured/How-Utilities-Are-Using-New-Technology-to-Protect-the-Grid
[17] Ibid.

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of the partnership include: Consolidated Edison of New York; Dominion Virginia Power; Entergy; Exelon Corporation; Hoosier; Energy; Great River Energy; Iberdrola USA; National Grid; New York Power Authority; Pepco Holdings, Inc.; Pacific Gas and Electric; Sacramento Municipal Utility District; San Diego Gas and Electric; Seattle City Light; Public Service Electric and Gas; TVA; and Xcel Energy.[18]

States and municipalities have also begun incorporating microgrids, adding an extra layer of resiliency and keeping critical infrastructure operating when the main power systems fail. In February 2015, New York's Gov. Andrew Cuomo announced NY Prize, a $40 million competition for microgrid design proposals. Winning proposals will be used to build microgrids for communities across the state.[19] New Jersey Transit received a $410 million federal grant to build a microgrid for its entire rail system. Woodbridge, CT is developing a microgrid to power town facilities like police and fire stations, schools, and town hall. Rikers Island jail in New York will also soon be powered by a microgrid.[20]

Question 2: Should the mandatory purchase requirement under section 210 of PURPA continue to have a place in parts of the country where it is currently in effect?

PURPA has a well-established history of encouraging diversification of our nation's electric generation and driving investment into cogeneration facilities and renewable energy. In the 15 years following passage of PURPA, cogeneration and clean energy generation experienced significant expansion.[21] Although some utilities have stated that the qualifying facilities provision imposes billions of dollars in excess costs, CAP is unaware of publicly available documentation of excessive costs imposed on utilities. Some public assertions by utilities of excessive costs have been criticized for including projects not seriously proposed or ever implemented.[22] Section 210 of PURPA has been effective at increasing renewable generation in areas served by monopoly electric utilities. In the event the Committee wishes to amend to this section, the Center for American Progress would recommend that the Committee ensure that any replacement policy guarantee the deployment of additional renewable energy generation.

Question 3: Do evolving energy exchange mechanisms, such as energy imbalance markets, offer a level enough playing field for small independent producers currently eligible to be designated as qualifying facilities under PURPA to compete successfully with incumbent utilities and power generators?

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[18] Department of Energy, "Partnership Description," available at http://energy.gov/epsa/partnership-description (last accessed May 2015).

[19] New York State Division of Homeland Security & Emergency Services, "Critical Infrastructure Protection and Resilience Quarterly Newsletter," Issue 9, (New York: April 2015), available at http://www.dhses.ny.gov/oct/documents/April-2015-CIPR-Newsletter.pdf

[20] Jeffrey Spivak, "A Developing Front in Resilience: Electricity Microgrids," *Urbanland*, February 17, 2015, available at http://urbanland.uli.org/sustainability/developing-front-resilience-electricity-microgrids/

[21] Bluestein Lihn, "Historical Impacts and Future Trends in Industrial Cogeneration."

[22] Barker, "Risch bill would free Idaho Power from forced buy if it shows it doesn't need more power."

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The Center for American Progress has not published on this topic and does not currently have a position on this issue.

Questions from Senator Ron Wyden

Question 1: In your opinion, what are the top three things that could be done to expand capacity and ancillary services markets to include resources such as energy efficiency, distributed generation and demand response?

CAP has proposed that Congress amend PURPA to require state public utility commissions to consider three policy standards:

- Boost energy-efficiency efforts through technology and regulation.
- Establish policies to encourage utilities to use clean energy to reduce pollution.
- Ensure utilities will have the resilience to function reliably in the future.

This proposal would be helpful in achieving the goals you highlight. CAP has provided a copy of the proposal to the Committee. It is also available on the CAP website at https://www.americanprogress.org/issues/green/report/2015/05/14/113159/a-forward-looking-agenda-for-the-nations-public-utility-commissions/.

In order to expand capacity and ancillary services markets to include energy efficiency resources, distributed generation, and demand response, regulators should evaluate the degree to which these technologies enhance grid stability and reliability. In a 2010 evaluation of RTO/ISO performance metrics, FERC found that the PJM ancillary services market saved PJM $80 million to $105 million annually.[23] Although ancillary services markets such as the one operated by PJM can support a market for demand response and ancillary services technologies, many of these technologies require regulatory guidance to achieve wider market access within states. Regulators can develop rate structures that value the contributions of ancillary services as a means to offset new transmission or generation. They can also clarify the designation of energy storage assets and eligibility of third-party owners of energy storage to provide the ancillary benefits associated with these technologies.

Additionally, energy efficiency investments are often cheaper than investments in new generation or transmission – about one-third the cost of new generation on a per kilowatt basis. Regulators should consider the role that efficiency programs can play in reducing consumer electric rates before approving new ratepayer financed investments. In order to preserve the utility rate base while supporting energy efficiency programs, regulators will need to develop regulatory incentives or changes to existing rate structures.

Furthermore, as noted in a recent Center for American Progress report, "Clean energy does not impose health risks on the communities they serve, can be placed closer to demand centers mitigating the need for additional investment in transmission, and with

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[23] Federal Energy Regulatory Commission, "PJM Interconnection," (2010) available at https://www.ferc.gov/industries/electric/indus-act/rto/metrics/pjm-rto-metrics.pdf

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microgrids that can operative independently of the traditional electric grid, can provide access to electricity during blackouts."[24] The DOE suggests that regulators consider the value of clean energy beyond the immediate benefits so that regulators can better serve their state consumers with "a portfolio of electricity options that meet their state specific goals for reliable, affordable, and clean electricity."[25] Regulators could calculate these benefits by assessing avoided costs of transmission and distribution upgrades, avoided costs of air pollution, and establishing metrics for increased reliability of distributed clean energy generation in the face of extreme weather. Regulators could also develop rate structures that value ancillary services provided by clean energy and energy storage technologies.

Question 2: I would like to make sure that as we develop the grid infrastructure of the future, we continue to protect the privacy rights of American citizens. Can you talk about some of the key ways in which we can hit the sweet spot of both tapping the potential of the smart grid while protecting privacy?

While consumers can benefit from having access to their energy usage data and offering access to third parties, the need for appropriate privacy safeguards is an inevitable policy concern. Specifically, consumers have expressed interest in controlling third parties access to this data.[26]

These protections could be offered by Congress through federal statute. Short of that, utilities and third parties can adopt the Voluntary Code of Conduct (VCC) framework established by the Department of Energy's Office of Electricity Delivery and Energy Reliability in coordination with the Federal Smart Grid Task Force. By following these guidelines, consumers will have greater confidence that their data is being handled responsibly.[27] The tenets of the VCC promote innovation while protecting the privacy consumer data and maintaining grid reliability, allow customers access to their own data, and avoid infringing on or superseding existing laws.[28] The National Institute of Standards and Technology also published guidance that organizations can adopt to enhance cybersecurity for smart grids.[29]

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[24] Dotson and Bovarnick, "A Forward-Looking Agenda."
[25] Department of Energy, "Modernizing the Electric Grid."
[26] David Perera, "Smart grid powers up privacy worries," *Politico*, January 1, 2015, available at http://www.politico.com/story/2015/01/energy-electricity-data-use-113901.html
[27] Department of Energy, "Data Privacy and the Smart Grid: A voluntary code of conduct," available at http://www.energy.gov/oe/downloads/data-privacy-and-smart-grid-voluntary-code-conduct (last accessed May 2015).
[28] Office of Electricity Delivery and Energy Reliability and the Federal Smart Grid Task Force, *Voluntary Code of Conduct (VCC) Final Concepts and Principles*, (Department of Energy, 2015), available at https://www.smartgrid.gov/sites/default/files/VCC_Concepts_and_Principles_2015_01_08_FINAL_1.pdf
[29] National Institutes of Standards and Technology, *Guidelines for Smart Grid Cybersecurity,* vol. 2 (2014), available at http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf

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California's Public Utility Commission has adopted rules to protect the privacy of electricity use data for customers of three large utility companies in the state, and requirements for reporting and audits on handling customer's data.[30] However, the law allows customers to give third party access to their data, at which point the third party controls the data. This structure necessitates transparency, so the customer understands explicitly what data they are sharing.

Questions from Senator Al Franken

Question 1: In response to my question during the hearing, you suggested some actions that utilities and regulators could take to make our grid more reliable and resilient in the face of more frequent and severe extreme weather events. For example, you noted that as a result of Hurricane Sandy, utilities now recognize the importance of making sure that substations are above the 50-year flood level. Could you please provide an estimate for the benefit-to-cost ratio of making such investments now, rather than after we experience another major grid outage?

Because electricity infrastructure varies by location as does the risks that infrastructure faces, an assessment of the benefit-to-cost ratio of proactive investments will vary by location as well. However, we know that when a community is not resilient to a natural disaster, the results can be disastrous. For example, Hurricane Sandy resulted in power outages for about 5 million residents in New York and New Jersey, and NJ Public Service Electric and Gas Company estimated that it needed to remove or trim 48,000 trees to restore power. The damage to power and gas lines was estimated at $1 billion, and many residents went several weeks without power, limiting daily life and commercial transactions.[31] There were also impacts that are hard to monetize. Hospital staff had to carry their patients out of darkened hospitals with no power. Rescue teams found elderly residents in high-rise buildings shivering with no heat or power. Most Americans would want to take action to avoid such situations, but such avoidance does not lend itself to a dollar figure.

The QER cited a study that found approximately $135 billion worth of damages to energy facilities along the Gulf coast could be avoided by investing $50 billion in resilience retrofits over the next 20 years. Investment in resiliency measures pre-storm serves as insurance. Whatever the estimated probability of a storm's likelihood may be (and the likelihood of an extreme storm event is only aggravated by climate change), resiliency measures reduce the risk of direct damage caused by event, and the subsequent impacts to people's livelihoods, residences, and health. Extreme weather event probabilities are

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[30] California State Public Utilities Commission, *Decision 11-07-056*, (July 28, 2011), available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/140369.htm
[31] Eric S. Blake and others, "Tropical Cyclone Report: Hurricane Sandy," (National Oceanic and Atmospheric Administration, 2013) p. 17, available at http://www.nhc.noaa.gov/data/tcr/AL182012_Sandy.pdf

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impossible to model, but the most effective way to address these risks is to preempt them with grid hardening measures.

Question 2: Distributed generation (DG) is one of the best tools we have for making electricity delivery more resilient, because it allows critical facilities to stay online even during an outage. In your opinion, what are the major barriers to—and benefits of—deploying more DG systems?

The primary barriers to DG deployment are not technological. This means that deployment of solar PV and other DG systems can be greatly expanded by overcoming institutional. In some parts of the country, electric utilities are emerging as a significant threat to DG technology. The utilities' traditional business model is based on consumer demand for electricity at a guaranteed rate. When consumers install solar PV on their rooftops, they are challenging this business model by reducing demand for centralized power. In 2013, the Edison Electric Institute (EEI) referred to "falling costs of distributed generation and other distributed energy resources" as "disruptive challenges." EEI concluded that the financial pressures from these disruptions "could have a major impact on realized equity returns, required investor returns, and credit quality."[32] As a result, some utilities are working to assess new fees on solar customers in what appears to be an effort to slow DG's market penetration.

Question 3: I recently introduced my Local Energy Supply and Resiliency Act of 2015 (S.1258), which will establish technical assistance and direct loan programs for distributed generation (DG) projects. These new programs will help identify, design, and deploy DG systems that generate electricity and useful thermal energy. In turn, states, tribes, utilities, and universities will be able to improve the reliability and resiliency of electricity delivery, reduce emissions, and maximize local job creation. In your opinion, will S.1258 help to accelerate the deployment of DG systems?

Legislation to help address any technical issues while providing financial incentives for development of DG projects will likely support accelerated deployment of these projects provided there is a market for the electricity that is generated.

Question 4: I know that the Center for American Progress has studied the economic and environmental impacts of liquefied natural gas (LNG) exports in great detail. In your analyses, have you found any export scenarios where American consumers and industries do not pay higher prices for natural gas and electricity? And what would be the impact of such a price increase on the manufacturing sector? Finally, what is the expected net climate impact of large volumes of LNG exports, based on your analyses?

On the economic impacts of LNG exports, CAP has not conducted an analysis to determine how much LNG the United States could export without increasing natural gas

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[32] Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," (Washington: Edison Electric Institute, 2013) available at http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

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prices. In January 2015, however, CAP released an analysis of the region-by-region and sector-by-sector impacts of high-volume LNG exports.[33] Under a scenario in which the United States exports 16 Bcf/d of LNG, manufacturers and other industrial consumers would pay 8.2 percent more for natural gas per year by 2020 than what is currently projected. Increases in industrial natural gas bills that year would be largest in the West South Central states of Arkansas, Louisiana, Oklahoma, and Texas, as well as in the Mountain states of Arizona, Colorado, Idaho, New Mexico, Montana, Nevada, Utah, and Wyoming. Under the scenario in which the United States exports 20 Bcf/d, industrial natural gas consumers in the Middle Atlantic states would pay 18.3 percent more per year than currently projected by 2040. In the New England states, they would pay 13.2 percent more per year.

On the climate impact of LNG exports, CAP has concluded that LNG exports could be defensible from a climate perspective if: (1) methane emissions are strictly controlled; (2) the exported LNG displaces coal-fired electricity generation or prevents new coal-fired generation; and (3) the exported LNG does not displace renewables and other low-carbon energy sources or slow the transition to a zero-carbon economy.[34]

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[33] Alison Cassady, "Potential Consumer Price Impacts of Efforts to Rapidly Expand Exports of Liquefied Natural Gas" (Washington: Center for American Progress, 2015) available at https://cdn.americanprogress.org/wp-content/uploads/2015/01/ConsumerCostsLNGExports.pdf
[34] Gwynne Taraska and Darryl Banks, "The Climate Implications of U.S. Liquefied Natural Gas, or LNG, Exports" (Washington: Center for American Progress, 2014) available at https://cdn.americanprogress.org/wp-content/uploads/2014/08/TaraskaLNG_report.pdf

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Questions for the Record Submitted to Mr. Jim Hunter

Questions from Chairman Lisa Murkowski

Question 1: Please elaborate on your ideas for strengthening the energy workforce, and especially for ensuring that the kind of successful joint apprenticeship programs your testimony highlighted.

a. What has been the most successful element of the National Utility Industry Training Fund that you mentioned in your testimony?

   Remembering that our purpose is to assist utility companies in providing cost-effective training to our members and future members, our boot camps have easily been our most successful effort. While community colleges and some "for-profit" schools can do a fine job, there are some issues in their business plan which can be a barrier to enrollment for many individuals. Most community college programs take two years to complete, and many individuals have personal responsibilities that prevent them from taking part for that length of time. The for-profit schools generally take about 16 weeks to complete but cost about $18,000.00 in tuition. Our boot camps can be customized to last from 6 to 12 weeks, depending on the needs of the local utilities. As a nonprofit, our cost for the 6-week version can run from $4500/person on the low end to $6000/person on the high end, depending on locality. For longer versions of our program, costs rise proportionately. Graduates have an adequate opportunity to experience the duties of the job, and employers have an opportunity to have a good look at the candidates to gauge their suitability for employment. Utilities have traditionally had a very high dropout rate (sometimes approaching 50%) with new apprentice linemen; however, DTE Energy's apprentice dropout rate with boot camp graduates has been less than 5%.

b. Your prepared statement mentions that "Our 6 week class runs about $6000 per person. We have received grants in Michigan and Kansas to run some boot camps and we have partnered with the local workforce investment board's to help with basic training needed for an applicant." What are the best features of this program that could be replicated more broadly?

   We have found that our association with the WIBs has provided us with an opportunity to connect with their client base, the long-term unemployed, which includes a diverse (race, gender, veteran status) pool of candidates. They do some preliminary testing to ensure the candidates have the necessary academic background and drug testing; and they have the resources to provide those in need with some of the required items for training, including adequate boots for climbing poles (which cost roughly $450/pair) and safety glasses cut to the individual's prescription (if needed). WIBs also do some preliminary interviewing to inform the candidates of our requirements and expectations; and they are ready, willing, and able to assist with grant administration. We believe the WIBs are valuable resources yet under-utilized by many employers.

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c. What is the biggest benefit of your boot camp and how does it compare with other alternatives?

   Our flexibility to respond to local needs in a cost-effective manner is probably the most noticeable benefit. While it is impossible to guarantee any graduate a job, we do not run a boot camp unless the local employer(s) have stated a need. Our for-profit counterparts generally run their schools as long as tuition money is available, regardless of local employment conditions.

Question 2: How do average salaries compare for energy sector jobs to other sectors?

Salaries in the energy sector are stable and include benefits such as health care and retirement plans. Our salaries average are over $39 an hour for lineman, which is the industry benchmark.

Question 3: Why do you think more young people aren't seeking out energy sector jobs? Is it an issue of awareness? Education and preparedness? Geography (where jobs are vs. where workers are)? Compensation?

Certainly the issues you raise are relevant. Students and job-seekers need to be aware of the great jobs in our industry, and all indications are that they are not prepared to take on the demanding requirements of these high-skill/high-wage jobs. Balancing the supply and demand for energy jobs is a complex question that encompasses both career awareness and education. It begins with strategic workforce planning to determine not just how many will be needed, but when, where and with what skills. Add to that the creation of an internal pipeline of candidates brought about by the changing generation mix and the introduction of new technology, and it becomes even more complex. Education initiatives must be matched to the availability and timing of job vacancies, and a diverse mix of students need information on the education and credentials that will lead to those jobs. We know what works: targeted career awareness that focuses on a diverse, qualified student population; training and education built on the skills needed to be successful in the job; and partnerships between training, education, and industry to stay in sync with changing industry requirements.

Question 4: How can we make energy sector jobs appeal to Millennials?

Jobs in the utility sector offer opportunities that young people are looking for. Our jobs are essential to the economy and our way of life, and our employees make a difference in the community. Our line positions appeal to the same people who are attracted to other community service jobs such as firefighters, police officers, and emergency medical technicians. Our engineering positions will appeal to those who are interested in building and maintaining an infrastructure

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that powers the country – the "largest machine in the country" - and to be part of an industry that is on the forefront of innovation. The key is targeting the students with the ability and desire to be successful in these great jobs.

Question 5: How can new technologies, such as superconductors, improve the nation's grid resiliency?

Redundancy on the grid is the best way to ensure resiliency. A modern smart grid with sensors and automated switching is important. New conductors and high-voltage DC lines will also improve the reliability of the grid. The system is changing rapidly due to market conditions and the addition of variable generation sources such as renewables. A strategy that incorporates renewables and the essential need for base load power plants along with load curtailment programs are necessary. A national energy strategy is needed to coordinate our system, and that will have to be done by Congress. We have a need for large transmission lines to transport the renewable resources such as wind from the areas of the country where they are plentiful and consistent to our load centers. Siting of transmission is the largest obstacle to building those needed lines. A national energy policy should look at how renewables and energy efficiency are incorporated into our system in a reliable and productive way, while assuring the backbone of our grid, base load generation, is compensated for its valuable contributions to a dependable system.

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Questions for the Record Submitted to Dr. Brian P. Kalk

Questions from Chairman Lisa Murkowski

Question 1: The hearing agenda included a number of PURPA "must consider" directives to State Public Regulatory Authorities, including my bill, S. 1219, to provide for the safe and reliable interconnection of distributed resources and to examine the effects of net metering to ensure such rates are "just and reasonable." Other measures, such as S. 1202, call for various interconnection standards and S. 1213, calls for different valuation methods, such as a new consideration of a "societal value of distributed energy resources" and an "avoided cost of transmission" ratemaking standard. S. 1213 would even expand the universe of QFs for the mandatory purchase obligation if a state regulatory authority declined to adopt these new valuations.

a. **As a state regulator, how do you respond to these various PURPA measures?**

As a state regulator, a balanced approach to regulation is crucial to encourage renewable energy development without sacrificing reliability and least cost principles. Regulators must evaluate whether the utility customer has an actual need for the energy, and whether any subsidized price cap costs will be allocated to that energy. S.1202 and 1213 would require states to make certain considerations that infringe on a state's jurisdiction. State authorities should not be tasked with creating a value proposition on behalf of project developers and at the expense of other utility customers whose interests the State Authority is equally obligated to protect.

The location of injection of energy becomes an important consideration for reliability, planning, congestion relief and contributor safety. Decisions like these are best left to the state regulators who are best positioned to determine the needs of the electric system and benefits presented by each proposal.

b. **How would S. 1213 depart from today's standard rate making?**

S. 1213 would defy standard rate making principals and strip states of their ability to allocate costs according to a least cost planning model. The current rate making process allows the state authority to review and test in great detail the composition of utility rates. A state's ability to protect customers from excessive rates would be unraveled if every customer were to act as their own utility and push resulting costs onto other customers.

Individuals are free to invest in independent energy supplies, but these costs should not be borne on the backs of other customers or society at large. Such proposals greatly impinge on states rate making authority.

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c. **How would you define "societal value of distributed energy resources"?**

Least cost planning is always important in energy development. Feed-in tariffs and assigning societal externality costs work in opposition of the least cost-planning model. North Dakota does not allow consideration of external values in resource planning or rate setting.

Attempting to create a level playing field for centralized and distributed resources by allocating a "societal value of distributed energy resources" will require significant changes in electric utility business models and markets. Customers will bear the burden of these changes by the drastic increase in costs they will experience.

<u>Question 2</u>: Are you concerned the distributed generation has resulted in improper cost shifting for consumers?

Yes, distributed generation can result in improper cost shifting for consumers. Utilities recover their investment and operating costs through fixed base and usage rates. If base rates are not set high enough to recover all of a utilities investment and fixed operating costs then portions of these costs are recovered through the customer's usage rate. When a distributed generation customer does not take enough their expected usage volumes, the utility company would under collect its needed revenue requirement and would need to recover those dollars from other customers.

a. **Is it fair for customers without rooftop solar panels to subsidize those who can afford to put solar on their homes?**

No. Customers should not bear the burden of increased costs resulting from other customers' utilization of distributed generation.

As a local example, Otter Tail Power Company (OTP) is a regional utility in North Dakota. OTP serves a large rural area with communities averaging around 400 people. These small rural towns have relatively low home valuations and aging populations. In many of OTP's communities over 20 percent of the households are comprised of someone over the age of 60 living alone. Some proposals require these people, who are not reasonable candidates for expensive solar generating systems themselves, to pay larger electric bills in order to subsidize costs for purchasers of solar panels. This is a regressive approach to electric ratemaking. This approach would transfer the costs of solar from purchasers (typically younger and more affluent) to non-purchasers (typically older and less affluent, such as in the small rural North Dakota towns mentioned above). Some argue this system is fair because non-purchasers could participate by choosing to purchase systems of their own. This claim is flawed because the

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fact that many electric customers cannot reasonably make such investments has been ignored.

b. How might utilities go about quantifying the costs of the ancillary services provided by the grid and ensuring that those costs are borne proportionally by all customers who utilize the grid?

Distributed generation customers **need to pay their total allocation of system infrastructure and fixed operating costs** as they still expect the utility's service to be available and adequate when their own resource is unavailable. Distributed generation tends to promote underutilization of the entire electric system, which results in higher costs to other customers.

Setting rates with appropriate fixed charges, as opposed to setting rates with artificially low fixed charges and higher per unit charges (kW or kWh), for most customers should result in proper cost allocation for the value of the grid. If customers have unusual load shapes, for example due to net metering, other charges might be required to adequately assess the value that they derive from the grid, including the value from ancillary services.

Regional Transmission Organizations (RTOs) with Independent System Operators (ISOs) have greatly improved the efficiency of ancillary service delivery and lowered costs. This is achieved through sharing a larger energy footprint with hundreds of various generation resources dispatched along with available transmission lines.

c. Does net metering account for the value of ancillary services provided by the grid?

No. Ancillary services (regulation, spinning reserves and supplemental reserves) are critical for keeping the grid balanced. However, net metering provides the benefit of a stabilized grid without accounting for ancillary service costs. Net metering typically results in the net-metered customer being over-compensated for the generation provided (e.g. at the retail rate rather than market rates). Therefore, the net amount paid by a net-metered customer is far too low to account for the grid services being obtained by the customer.

Question 3: How can new technologies, such as superconductors, improve the nation's grid resiliency?

New technologies, such as superconductors, can help to improve the efficiency of the nation's grid. However, these new technologies do not assist in improving the nation's grid reliability because factors such as weather and cyber security will always exist.

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Superconductors allow flexibility of the grid due to increased capacity over standard aluminum or copper conductors of the same diameter. Superconductors are expensive and typically only cost justified when driven by large amounts of power to transmit over short distances (heavily populated areas that have limited rights-of-way available). This situation is not readily apparent in North Dakota. Therefore, it is not presently realistic to think superconductors will improve grid resiliency in North Dakota.

Question 4: There appears to be consensus that the federal permitting process for transmission project must be improved. Do you agree? What can Congress do to bring some reasonableness and certainty to this byzantine process?

Yes. The federal permitting process for transmission projects needs improvement. The federal agencies need to adhere to established statutory schedules and timelines to ensure the process continues in a timely manner. Congressional efforts to establish a definitive timeline for federal agency action from the time data is collected, until a record decision is completed would be greatly appreciated.

North Dakota supports states' continued role and authority over siting and permitting of transmission projects, and this authority should not be shifted outside of the state.

RTOs can identify new projects and confirm the "need" for projects, but the states should ultimately retain the authority they possess over siting and permitting. The federal government needs to defer to states and RTOs who possess first-hand knowledge of needs and special considerations for a particular region.

North Dakota has a workable process. In North Dakota, state authority does not apply until the voltage rises above 115 kV. Smaller projects (115 kV and lower) are permitted by local units of government (townships, counties), which generally results in an expeditious review of projects. There is no readily identifiable justification or driver for Congress to mandate a process that will likely add complexity and additional costs upon consumers.

a. **What could other states and the federal government learn from North Dakota's system?**

   States and the federal government can look towards North Dakota's model of transmission siting and adherence to statutory time schedules. North Dakota's process trusts local units of government to approve transmission line routing for smaller projects, while larger projects come before the state's Public Service Commission for siting approval.

b. **What are the biggest federal obstacles that slow it down?**

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The federal government needs a shorted timeframe with reduced federal intervention. The "one size fit's all" regulatory process does not work. States like North Dakota with limited federal lands can operate much differently than other states with a large percentage of federal lands.

Another challenge is the lack of focus federal staff members allocate to particular projects. Federal staff members are typically spread thin and have more projects on-going than time available. This is seen with Environmental Impact Statements, which take the longest from a procedural standpoint.

<u>Question 5</u>: Can you speak to some of the ways addressing grid integration might vary by state and by region?

a. **What are some of the advantages of different states having different policies?**

Each state possesses its own unique opportunity for generation and transmission development. For example, a micro-grid in Alaska might work well due to the population pockets spread across the state. However, that same micro-grid technology would not work well in highly populated areas with access to generation.

b. **Can you give some specific examples of policies that work well in one region, but would be problematic in another?**

The interconnection of thousands of MWs of wind generation in the Midwest has maximized the usage of the rural transmission system. The RTO/ISO's have developed Energy Market Rules to incent the wind resources to be dispatchable and operate on the same playing field as other traditional generation resources. This may not be the case in the Western Energy Coordinating Council.

Another example is the use of transmission. The use of transmission voltage levels differ across various regions.

A notable accomplishment is the collaboration between the Organization of MISO States, Upper Midwest Transmission Development Initiative (five states), Midwest Governors, and MISO to develop a plan for major transmission infrastructure throughout MISO that address reliability, congestion, and public policy and demonstrated to benefit customers far in excess of the cost of the collaboratively evaluated and planned build-out (i.e., the Multi-value Projects).

c. **What do you see as the appropriate role for the federal government?**

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The federal government should encourage state involvement in the FERC, leave energy planning to the states and RTOs, and avoid regulations such as the Environmental Protection Agency's 111D rules.

Question 6: What role can micro-grid technology play in grid security and stability, as well as localized economic growth?

Micro-grid technology can negatively affect the planning process and role of RTOs. Micro-grids can incur problems when they try to interconnect to other systems. This can be a detriment to grid security and stability. Similar to the example provided in answer 5a., the feasibility and need for micro-grid technology is highly dependent on a state's population congestion and access to generation.

States play a major role in how and at what pace a transition to micro-grids may occur. State regulators review and approve expenditures and set rates for investor-owned utilities in their states. State policy makers operate within a highly structured legal and regulatory framework. States will need to take a key role in evaluating customer value, consumer protections, utility risk and cost-recovery, for innovative grid modernization investments.

Question 7: To what extent are states currently pricing in the value of ancillary services? What states are the leaders in this area?

States leading in this area are turning over their ancillary service provisions to the respective RTO/ISO energy markets. Those states not participating in a regional RTO/ISO will see the advantages of pooled resources and transmission usages.

The value of an RTO for the pricing of ancillary services is significant. The larger the pool of resources, the more efficient the ancillary services can be provided. MISO's geographic diversity was a "game changer" in supporting the large amounts of intermittent resources in its footprint and predominantly in the western portion of MISO, including North Dakota.

Question 8: Regarding S. 1220, to what extent are cross-border infrastructure collaborations ongoing?

North Dakota has experienced various levels of federal involvement depending on whether the type of project is for pipelines or transmission.

a. **Are there examples where the U.S.-Canada and U.S.-Mexico collaborations are working well?**

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Prior to the recent administration, it was possible to work through federal agencies to undertake international collaboration. In general, transmission projects have worked fairly well whereas, pipeline projects have experienced additional hurdles.

A North Dakota specific example of cross border collaboration is the coordination with the Harvey, ND to Glenboro, Manitoba 230 kV line energized in 2002. This project was collaboration between Manitoba Hydro, Northern States Power Company (NSP), and OTP. In this region, there is a standing Manitoba Hydro Coordinating Committee that is active to discuss current issues between the tie-line owners. The US-Canada relationship and collaboration is strong in North Dakota and the surrounding area. This is further evidenced by Minnesota Power's current collaboration with Manitoba Hydro on the Great Northern Transmission Line in Minnesota.

Additionally, interconnections will exist with SaskPower when it becomes a Tier I adjacent utility with the Southwest Power Pool on October 1st, 2015.

b. Are there areas where they could be improved?

In the area of transmission, certainly. North Dakota's Canadian neighbors must follow most of the energy market rules and reliability rules set forth by FERC and NERC. To the extent NERC has increased its regulatory position, a greater inclusion of Canadian utilities should exist to share in the development of a secure and reliable grid.

Everyone is aware of the current status of the Keystone Pipeline. North Dakota has approved several pipeline projects that now hinge on decisions from federal agencies.

The Alliance for Industrial Efficiency

April 23, 2015

The Honorable Jeanne Shaheen
520 Hart Senate Office Building
Washington, DC 20510

Dear Senator Shaheen:

The undersigned businesses, labor, and environmental organizations are committed to encouraging the use of Combined Heat and Power (CHP) and Waste Heat to Power (WHP) to enhance U.S. manufacturing competitiveness, increase energy efficiency, and improve the environment. We write to thank you for your work on the forthcoming Heat Efficiency through Applied Technology Act ("HEAT Act"). Your bill will help overcome regulatory barriers that have prevented CHP and WHP from reaching their full potential. We look forward to working with you in the coming months to see that this important legislation is enacted into law.

CHP and WHP provide a clean and efficient source of homegrown energy that can help make U.S. manufacturers more competitive. By generating both heat and electricity with a single fuel source, CHP is significantly more efficient than the conventional separate generation of heat and power. By capturing waste heat from existing industrial processes, WHP can generate additional electricity with no incremental emissions. Combined, these technologies offer significant economic, resiliency, and emission benefits to the nation's factories, hospitals and universities. In 2012, the Department of Energy and EPA found that as much as 130 Gigawatts of clean and efficient CHP technical potential remains in the commercial and industrial sectors. That same year, EPA estimated that an additional 15 Gigawatts of clean power could be produced using WHP. Yet, a variety of regulatory hurdles have prevented these technologies from reaching their full potential.

The HEAT Act takes a critical step toward reducing these hurdles by requiring the Department of Energy and Federal Energy Regulatory Commission (FERC) to develop materials to identify best practices for interconnection procedures and supplemental, backup and standby power fees. It further provides resources to help states develop environmental regulations that recognize the benefits of energy efficiency. This bill does not mandate that states adopt any new regulations, but instead provides important tools that states can choose to use to help overcome historic barriers to efficiency. These regulatory tools will help increase customer choice by giving potential CHP and WHP hosts the ability to produce their own energy.

The Department of Energy has long recognized interconnection, standby fees and tariffs, and environmental permitting as issues that could be streamlined to encourage greater CHP and WHP deployment. The HEAT Act takes an important step in this direction. In so doing, this bill will spur investments in

manufacturing competitiveness within the steel, aluminum, glass, chemical, and other energy-intensive industries. What's more, because CHP projects can operate independent of the grid, this legislation will help America's factories, hospitals, and universities "keep the lights on" during extreme weather events.

We appreciate your efforts to support American manufacturing competitiveness. Our businesses and organizations support The Heat Act and look forward to working with your office to help it to become law.

Sincerely,

Jennifer Kefer, Director
Alliance for Industrial Efficiency

Traci Kraus, Manager, Government Relations
Cummins Inc.

Elizabeth Thompson, Vice President, U.S. Climate and Political Affairs
Environmental Defense Fund

Susan Brodie, Executive Director
Heat is Power Association (HiP)

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Elinor Haider, Vice President, Market Development
Veolia North America

Mark Bescher, Government Relations
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Holly R. Hart, Legislative Director
United Steelworkers (USW)

The Honorable Lisa Murkowski
Chairman
U.S. Senate Committee on
Energy & Natural Resources
709 Hart Senate Office Building
Washington, D.C. 20510

The Honorable Maria Cantwell
Ranking Member
U.S. Senate Committee on
Energy & Natural Resources
511 Hart Senate Office Building
Washington, D.C. 20510

May 28, 2015

Chairman Murkowski and Ranking Member Cantwell:

We are writing to express our support for the Clean Energy Grid Integration Act (S. 1201). We are grateful for Senator Shaheen's leadership in expanding opportunities for clean and efficient distributed generation and we are hopeful that this provision will be incorporated into the Senate Committee on Energy and Natural Resource's forthcoming energy package. We believe that the Clean Energy Grid Integration Act will help make the U.S. electric grid more resilient, provide flexibility to U.S. electricity customers, and reduce emissions. The undersigned businesses and organizations represent end users, developers, and installers for a variety of distributed-generation technologies that will benefit from this legislation.

Centralized power generation is costly and difficult to locate. Clean and efficient, distributed generation sources can be deployed at a fraction of the cost, enabling the grid to be more resilient. This is particularly true in the case of energy sources that can function independent of the grid, providing enhanced reliability during extreme weather events, which may compromise central power plants. Distributed generation is also more efficient and avoids line losses associated with the transmission and distribution of centralized electricity. By investing in distributed generation, we can avoid costly upgrades to transmission and distribution infrastructure.

Consumers should have the freedom to choose the type of energy that powers their homes and businesses. Unfortunately, a variety of barriers, like complicated and burdensome interconnection procedures, prevent distributed energy sources from reaching their potential. The Clean Energy Grid Integration Act helps identify and overcome these barriers, so that the U.S. electricity system can be more diverse and resilient.

The Clean Energy Grid Integration Act reports on the status of grid integration and examines barriers that are limiting distributed generation sources from successfully connecting to the grid. It then establishes a stakeholder working group to determine the most appropriate way to overcome these barriers and provides competitive grants to states to demonstrate best practices for successfully integrating clean, distributed energy sources into the electricity grid. This low-cost approach identifies a problem and provides incentives for states to determine the best way to overcome it. It does not place any mandates on states or utilities.

We look forward to helping this important legislation become law and in continuing to work with your office to explore – and overcome - barriers to deploying the clean, efficient and renewable technologies represented by our businesses and organizations.

Sincerely,

Alliance for Industrial Efficiency
Jennifer Kefer, Executive Director

Alliance to Save Energy (ASE)
Brad Penney, Interim Director of Gov't Relations

American Council for an Energy-Efficient Economy
R. Neal Elliott, Assoc. Director for Research

Biomass Thermal Energy Council (BTEC)
Joseph Seymour, Executive Director

Conservation Services Group
Pat Stanton, SVP Policy & Advocacy

Environmental Defense Fund
Elizabeth Thompson, Vice President, U.S. Climate & Political Affairs

Heat is Power Association (HiP)
Susan Brodie, Executive Director

International District Energy Association (IDEA)
Robert Thornton, President & CEO

Midwest Cogeneration Association
Patricia Sharkey, Policy Director

National Association of Energy Service Companies (NAESCO)
Donald Gilligan, President

National Electrical Contractors Association (NECA)
Marco Giamberardino, Executive Director, Government Affairs

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Phyllis Cuttino, Director, Clean Energy Initiative

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John D. Prunkl, President & CEO

Sheet Metal & Air Conditioning Contractor's National Association (SMACNA)
Stan Kolbe, Director Government Relations

Sheet Metal, Air, Rail and Transportation Workers (SMART) International Association
Joseph Sellers, General President

The Association of Union Constructors (TAUC)
Stephen R. Lindauer, CEO

Unilever
Mark Bescher, Government Relations

United Steelworkers
Holly R. Hart, Legislative Director

Veolia North America
Elinor Haider, Vice President, Market Development

American Public Power Association

Statement of the

AMERICAN PUBLIC POWER ASSOCIATION

Submitted to the

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

For the May 14, 2015

"Hearing on Energy Infrastructure Legislation"

(Submitted May 28, 2015)

The American Public Power Association (APPA) appreciates the opportunity to provide the following statement to the House Subcommittee on Energy and Power on the May 12, 2015, "Discussion Draft Addressing Energy Reliability and Security" (Discussion Draft). APPA is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the U.S. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA. Collectively, public power utilities deliver electricity to one of every seven electricity consumers. We serve some of the nation's largest cities, including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. However, most public power utilities serve small communities of 10,000 people or less.

In terms of public power's generation portfolio, in 2013 these utilities generated 169.6 million megawatt-hours (MWhs) of electricity from coal; 76.9 million MWhs from natural gas; 62.78 MWhs million from nuclear; 69.8 million MWhs from hydropower; and 8 million MWhs from other sources such as non-hydropower renewable energy like wind, solar, and geothermal. It is important to note, however, that public power utilities supply approximately 15 percent of electricity to end-users in the United States, but they only produce 10 percent of the megawatt-hours generated. To make up the difference, public power utilities purchase power at wholesale from other entities such as investor-owned utilities, independent

power producers, rural electric cooperatives, federal power marketing administrations, and the Tennessee Valley Authority.

More detailed comments on the legislation of concern to public power utilities discussed at the May 14 hearing follow.

S. 485 -- "Assuring Private Property Rights Over Vast Access to Land Act" or the "APPROVAL Act"

This bill would amend section 1222 of the Energy Policy Act of 2005 (EPAct05) to prohibit the Secretary of Energy and the Administrators of the Western Area Power Administration and of the Southwestern Power Administration from using the power of eminent domain to implement modernization of electricity transmission infrastructure, unless they have received explicit permission to do so by: (1) the state governor and the head of each applicable public utility commission or public service commission of the affected state, and (2) the head of the governing body of each Indian tribe whose land would be affected. An electricity transmission infrastructure project, to the greatest extent practicable, must be sited upon either an existing federal right-of-way or upon federal land managed by either: (1) the Bureau of Land Management, (2) the Forest Service, (3) the Bureau of Reclamation, or (4) the Corps of Engineers.

APPA supports efforts to amend section 1222. Approximately 580 public power utilities buy power from the four federal Power Marketing Administrations, including the Southwestern Power Administration (SWPA) and the Western Area Power Administration. These public power utilities (particularly in SWPA where the authority has been used) have been concerned that, as Section 1222 has been implemented since the passage of EPAct05, they could potentially have to pay for transmission lines that they do not need.

S. 1017 (To Improve Siting of Interstate Electric Transmission Facilities)

This legislation would amend the Federal Power Act (FPA) to provide the Federal Energy Regulatory Commission (FERC) narrow authority to approve and site new priority electric transmission lines in cases where local or state approval processes have been unsuccessful.

APPA supports the goals of this legislation. We do, however, have concerns about the scope of the legislation. Specifically, the definition of "high priority regional transmission project" seems overly broad, giving FERC too much authority to overrule a state action. Additionally, the legislation requires FERC, in making a determination of public convenience and necessity, to consider whether the facilities covered by the application are part of "an Interconnection-wide transmission grid plan for a high-priority regional transmission project." However, the legislation provides no definition of an "(i)nterconnection-wide transmission grid plan."

S. 1037 (To Expand the Provisions for Termination of Mandatory Purchase Requirements)

This bill amends section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 (16 U.S.C. § 824a-3) to provide that no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility if the state regulatory agency having ratemaking authority over the utility has determined that the utility has no need to acquire additional generation resources in order to meet its obligation to serve customers in the public interest.

As drafted, relief could only be provided to utilities subject to state regulation, excluding the vast majority of public power utilities, which generally are not subject to state regulation. As a result, APPA cannot support the bill in its present form. APPA is also concerned that S. 1037 would put FERC in the role of reviewing retail resource adequacy decisions by state rate regulators. This is not an appropriate role for FERC and, while APPA supports the legislation's goals, we would urge that the bill be amended to eliminate this expansion of FERC's jurisdiction.

Currently, section 210(a)(2) of PURPA (16 U.S.C. § 824a-3(a)(2)) requires FERC to adopt rules requiring any "electric utility" to offer to purchase electric energy from a qualifying facility (QF).

Section 210 of PURPA uses the definition of "electric utility" in section 3(22) of the FPA (16 U.S.C. § 796(22)), which includes any person or federal or state agency that sells electricity. This definition includes both a state-regulated electric utility and what section 210 of PURPA calls a "nonregulated electric utility" (16 U.S.C. § 824a-3(f), (g), (h)) or a "non-regulated electric utility," (16 U.S.C. § 824a-3(m)(6)). The Energy Policy Act of 2005 added to section 210 a new subsection (m), which provides for the termination of the mandatory purchase obligation of both state-regulated and non-regulated electric utilities if FERC finds that the QF has nondiscriminatory access to wholesale energy and capacity markets as described in subparagraphs (m)(1)(A), (B), and (C).

Under S. 1037, a new paragraph (m)(3) would be added and the current paragraph (m)(3) would be renumbered (m)(4). But by its terms, the new paragraph (m)(3) would only authorize the termination of the purchase obligations of state-regulated electric utilities:

> (3) STATE DETERMINATION. – After the date of enactment of this paragraph, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the State regulatory agency having ratemaking authority over the electric utility has determined that the electric utility has no need to acquire additional generation resources in order to meet its obligation to serve customers in the public interest.

In most states, however, public power utilities are not subject to state rate regulation. As a result, the ability to determine that a utility is relieved of its purchase obligation would not extend to the vast majority of public power utilities. APPA could support relieving electric utilities of their mandatory purchase obligation under section 210 of PURPA if the determination provided in S. 1037 can be made for any electric utility, not just for those subject to state rate regulation. Conversely, excluding public power utilities from the relief provided by S. 1037 is not only inequitable, but also would be contrary to the existing provisions of section 210 of PURPA, which treat public power utilities and state-regulated utilities comparably.

That problem could be fixed by adding corresponding language allowing a non-regulated electric utility to make the same determination as a state regulatory commission:

> (3) STATE <u>OR UTILITY</u> DETERMINATION. - After the date of enactment of this paragraph, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the State regulatory agency having ratemaking authority over the electric utility <u>or the non-regulated electric utility</u> has determined that the electric utility has no need to acquire additional generation resources in order to meet its obligation to serve customers in the public interest.
>
> (Proposed changes underlined.)

Modifying S. 1037 in this manner would track the existing provisions of PURPA section 210 requiring state regulatory commissions or non-regulated utilities to implement FERC's mandatory purchase obligation rules and authorizing FERC to enforce those rules against state regulators and non-regulated electric utilities. (See 16 U.S.C. § 824a-3(f), (g), (h).)

With or without the above amendment, the new paragraph (m)(3) read in isolation would appear to be self-implementing—i.e., upon the determination, the purchase obligation would cease. But other provisions of S. 1037 would require an independent determination by FERC. These provisions would amend the current paragraphs (m)(3) and (m)(4) and renumber them as (m)(4) and (m)(5), respectively. As amended and renumbered, paragraph (m)(4) would require the electric utility to apply to FERC to review the (m)(3) determination by its state regulator (or with the above amendment, the determination by the non-regulated electric utility), and FERC would have to make its own determination before the purchase obligation would terminate. Similarly, amended and renumbered paragraph (m)(5) would allow FERC to reinstate the purchase obligation if facts change. If the new paragraph (m)(3) added by S. 1037 were amended as described above, the rest of S. 1037 would not need further amendment and would work fairly for both categories of electric utilities.

As discussed above, APPA is also concerned that S. 1037 puts FERC in the role of reviewing retail resource adequacy decisions by state rate regulators. Specifically, the legislation would require FERC to review the state rate regulator's determination of whether an electric utility "has no need to acquire additional generation resources in order to meets its obligation to serve customers in the public interest."

That is quite different from the findings that FERC makes when relieving an electric utility of its purchase obligation under subsection (m)(1); i.e., whether there is a competitive wholesale market and open access transmission service. APPA believes that the provisions allowing FERC review of the state regulator determination (or non-regulated utility determination as we propose S. 1037 be amended to include) could be dropped from S. 1037 without defeating the bill's overall objectives.

S. 1201 -- Clean Energy Grid Integration Act

The legislation would require the Department of Energy (DOE) to carry out efforts for advancing the integration of clean distributed generation (DG) into electric grids. DOE would be required to draft a report identifying and quantifying "the benefits to all stakeholders of expanded integration of clean energy into the grid," and identifying technical issues and regulatory barriers preventing or inhibiting integration. DOE would be authorized to issue up to $15 million in grants for research to overcome technical barriers identified in the report. DOE would form a working group consisting of interest groups it determines have an interest in DG integration with the goal of recommending actions to reduce regulatory burdens to DG integration. Finally, the legislation authorizes grants of up to $5 million for distributed generation integration demonstration projects.

As discussed further below, APPA believes DG can, and should, play an important role in public power's renewable energy portfolio. APPA also appreciates the fact that the legislation seeks to facilitate integration of DG into the grid, rather than imposing a federally-mandated approach to doing so. We would note, however, that any discussion of DG should be balanced and frank. For example, the legislation would be improved by requiring DOE's report on DG to consider both the costs and benefits to stakeholders of DG. Likewise, a working group on DG integration would benefit from representatives from all sectors – a result that is not necessarily guaranteed as the bill is drafted.

S. 1202 – "Heat Efficiency through Applied Technology Act" or "HEAT Act"

The legislation would amend section 111(d) of PURPA (16 U.S.C. § 2621(d)) to require DOE, along with FERC, to establish: guidance for technical interconnection standards; model interconnection procedures; and model rules for determining and assigning interconnection costs. These standards are intended to encourage the use of distributed generation, such as combined heat and power technology and waste heat power technology. The legislation then requires each state regulatory authority and non-regulated covered utility to consider adopting these standards.

The legislation would also require DOE to establish model rules for determining fees or rates for supplementary power, backup or standby power, maintenance power, and interruptible power supplied to facilities that operate combined heat and power technology and waste heat to power technology that appropriately allow for adequate cost recovery by an electric utility, but are not excessive. Again, the

legislation then requires each state regulatory authority and non-regulated covered utility to consider adopting these rules.

APPA believes that it is appropriate for DOE to establish such guidance, model procedures, and model rules, but APPA believes operational and ratemaking decisions are best made at the state and local levels. As a result, APPA would oppose any effort to require the more than 120 public power utilities covered by section 111(d) of PURPA to go through the formal process of considering and adopting or rejecting these new requirements.

S. 1207 – Next Generation Electric Systems Act

The legislation would create a competitive grant program to stakeholder partnerships working to modernize electric grid operations, with the goal of accommodating additional renewable sources, energy storage systems, and DG and a focus on delivering affordable and reliable service to communities. APPA supports the legislation's goals and appreciates the fact that it would facilitate work among stakeholders to achieve these goals rather than imposing a federally-mandated approach.

S. 1213 – "Free Market Energy Act"

APPA believes DG can, and should, play an important role in public power's renewable energy portfolio. Public power utilities will continue to work collaboratively with their customers to deploy solar DG as well as community-scale solar farms. APPA members have said that in order to continue fostering the growth of DG, and rooftop solar in particular, it is important that DG customers pay their fair share of the costs of keeping the grid operating safely and reliably. Net-metering policies and feed-in tariffs (FITs) need to be designed to reflect costs and assure that those who benefit from the grid are sharing in the cost of building and maintaining it. In addition, consumers must be protected from deceptive or misleading practices by third-party sales and leasing companies. While, policing deceptive practices could fall under the jurisdiction of several federal agencies, including the Federal Trade Commission, distributed generation issues are generally retail level issues and, so, not subject to FERC authority.

S. 1213 seeks amend the FPA to expand the role of FERC to give it authority over distributed energy resources on an "electricity distribution system." APPA opposes this effort to federalize what is rightfully a state and local issue and therefore opposes the bill.

Section 210 of PURPA (16 U.S.C. § 824a-3), discussed above, also requires utilities to interconnect with any QF. S. 1213 would create a new section 5 in PURPA, which would appear to be intended to require utilities to interconnect with distributed energy resources (DER). Of concern—or at the very least causing ambiguity—is the fact that S. 1213 would place the new Section 5 to PURPA as a standalone provision

outside of either Titles I or II of the Act. It is unclear whether this is a drafting error or intended to provide that new PURPA section 5 supersedes the provisions of Titles I and II.

New section 5 preempts PURPA section 210 interconnection rate methodologies in favor of a structure that requires interconnecting utilities to take into account any "benefits" the DER is providing the grid and to prove that the interconnection charges are set at actual cost of service. The latter calls into question how much utilities could recover as stranded costs, which DER providers will argue are not "actual" costs. In addition the new section 5 says such rates must be just and reasonable and not "punitive."

The legislation also amends Section 111(d) of Title I of PURPA (16 U.S.C. § 2621(d)), discussed above, to add new paragraph (20) that would obligate state public utility commissions to consider requiring that regulated utilities compensate eligible DER services under specific rate terms. DER would be eligible to receive time-of-use pricing for power sold to utilities and to be compensated for capacity, demand response, conservation, ancillary services sold, and for the "societal value" of DER. The provision would only apply to state regulated utilities, so would not affect most public power utilities. However, the legislation would also add a new paragraph (21) to section 111(d) of PURPA, which would apply to both state-regulated and nonregulated electric utilities in a state that has determined not to establish standards under the new paragraph (20). Under this new paragraph (21), a state public utility commission or nonregulated electric utility would have to consider a rate methodology for DER that likely would be much higher than the rates that would be imposed under the new paragraph (20). Moreover, any state which fails to adopt the new paragraph (20) standards would be overruled such that the definition of QF would be expanded to include DER within that state. As a result, electric utilities in that state would be required under section 210 of PURPA (16 U.S.C. § 824a-3) to purchase the same services from DER and QFs.

S. 1217 -- "Electric Transmission Infrastructure Permitting Improvement Act"

APPA supports the apparent goals of this legislation but believes it would benefit from further clarification.

First, the bill establishes an Interagency Rapid Response Team for Transmission (IRRTT). This team's mission is to improve the timeliness and efficiency of permitting for electric transmission "infrastructure" and to facilitate the performance of maintenance and upgrades to electric transmission lines. APPA supports that mission. The bill would benefit from defining the scope of the "electric transmission infrastructure" to which it applies. For example, is the term "infrastructure" intended to include more than physical transmission lines or facilities? Does it only include infrastructure used in interstate transmission?

Second, the bill establishes a "Transmission Ombudsperson" at FERC. However, it is unclear how the IRRTT's mission and duties, and those of the FERC "Transmission Ombudsperson," relate to section

216(h) of the FPA (16 U.S.C. § 824p(h)), which also seeks to improve interagency coordination of transmission facility approvals. Section 216(h), however, makes DOE the lead agency to coordinate federal authorizations of transmission facilities; directs DOE to coordinate with state agencies and Indian tribes on approvals for such facilities; provides for appeal to the President of federal agency denials or failures to act; and requires federal agencies to enter into a memorandum of understanding to facilitate federal approvals. It is unclear how the functions of the IRRTT and Transmission Ombudsperson would supplement or replace the functions of DOE under section 216(h).

S. 1219 – "Interconnecting Distributed Resources and Examining Net Metering"

The growth of distributed energy resources will create new challenges for all electric distribution utilities, including public power utilities. These challenges include interconnection standards and rate treatments. This bill requires examination and determinations by electric utilities of certain of these issues. Because electric utilities have adequate incentives to consider these issues already, and their individual circumstances vary substantially, this bill's requirements are unnecessary and impose burdensome compliance costs on electric utilities, including many public power utilities. APPA, thus, opposes the bill in its current form.

As discussed above, Section 111(d) of PURPA (16 U.S.C. § 2621(d)), requires each "state regulatory authority" and each "nonregulated electric utility" to consider and make certain determinations concerning a variety of ratemaking and service issues. Section 112(b) of PURPA, 16 U.S.C. § 2622(b), establishes time limits to commence and complete this consideration and determination. These provisions apply with respect to an electric utility if its total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during a calendar year (16 U.S.C. § 2612(a)). As noted above, this includes more than 120 public power utilities.

Sections 1 and 2 of S. 1219 amend section 111(d) of PURPA by adding new paragraphs (20) and (21), which require each "state regulatory authority" to consider and make determinations regarding additional issues concerning retail and distribution service.

Section 1 adds paragraph (20), which requires proceedings to examine the degree to which "distributed resources" directly connected to the distribution network contribute "ancillary services," and to prescribe measures to ensure ancillary services so that "grid interconnection" for distributed resources is "safe, reliable and efficient." For this purpose, a "distributed resource" is an "electric power source directly connected to the distribution network or on the customer side of the meter." The bill broadly defines "ancillary services" to include reactive supply; regulation and frequency response; energy imbalance; operating reserves; generation imbalance; and flexibility and ramping services."

Section 2 adds paragraph (21), which requires proceedings to examine the effects of net metering and customer-owned distributed generation on resource planning of each electric utility, including issues such

as cost-shifting to other customers and the financial health of the entity providing distribution service; and to determine whether net metering rates are "just and reasonable and not unduly discriminatory or preferential, in accordance with State law."

Read in isolation, the two new paragraphs of section 111(d) would appear to apply only to a "state regulatory authority." But Section 3 of S. 1219 amends section 112(b) of PURPA to require "each state regulatory authority (with respect to each electric utility for which it has ratemaking authority) *and each nonregulated electric utility*" (emphasis added) to commence consideration of the above two issues within one year after the bill's enactment, and to complete that consideration and make the required determinations within two years. Thus, S. 1219 applies these new requirements to all utilities covered by section 111(d) of PURPA, including public power utilities that are "nonregulated electric utilities" as well as utilities that are subject to state rate regulation.

APPA believes that the matters covered by proposed paragraphs (20) and (21) are state and local matters, and the federal government need not and should not be mandating the consideration of these factors. Public power distribution utilities already have incentives to ensure that distributed energy resources are interconnected in a safe, reliable, and efficient manner. They also have an incentive to determine the effect of distributed energy resources on the operations of the distribution network and the need for the utility to ensure that necessary ancillary services are provided.

As for the proposed paragraph (21), public power utilities have the authority and the incentive to study the effect of net-metering and feed-in tariffs on their resource planning, costs, rate structures, and compliance with state laws. One of the reasons they have that incentive, however, is that public power utilities subject to section 111(d) of PURPA are required by existing paragraph (11) to make available upon request net-metering service. If proposed paragraph (21) is to be added, existing paragraph (11) should be removed, or at least the obligation to provide net-metering service under paragraph (11) should be subject to the outcome of the proceedings required by new paragraph (21).

S. 1220 – "Energy Distribution Act"

S. 1220 adopts recommendations from the Quadrennial Energy Review by directing DOE to improve the understanding of "energy security" across the federal government; directing DOE to lead interagency efforts on "shared energy infrastructure" data collection and analysis; and authorizing a program to share data with Mexico and Canada on cross-border energy flows.

APPA supports the goals of this legislation.

S. 1227 (To Promote Hybrid Micro-Grid Systems)

APPA represents public power utilities in Alaska, American Samoa, Guam, the Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands. Many of these utilities provide remote communities with electricity that is primarily generated from expensive, imported diesel fuel. The utilities serving these communities are very interested in diversifying their fuel sources and not relying so heavily on expensive diesel. In particular, they are interested in exploring renewable energy sources that would not require the importation of fuel.

As the Chairman of this Committee is well aware, Alaska is a leader in the development and operation of micro-grids. The state has between 200 to 250 permanently islanded micro-grids. These micro-grids range in size from 30kW to more than 100 MW (for larger, remote hydropower systems). Some of these micro-grids have existed for over 50 years and provide electricity to isolated, rural communities. Alaska's isolated hybrid micro-grids use renewable energy sources, such as wind, solar, hydro, biomass, and tidal currents, paired with diesel generation.

APPA is supportive of efforts to examine technologies that could potentially reduce dependence on diesel fuel, improve reliability, and lower the cost of electricity. S. 1227 would direct DOE to develop an implementation strategy to promote the development of hybrid, micro-grid system technologies for isolated communities. It would also seek to leverage local capacity and knowledge in developing such systems. APPA believes DOE should work with isolated communities to promote the innovative use of hybrid micro-grids and supports Chairman Murkowski's bill directing it to do so.

S. 1232 -- "Smart Grid Act"

APPA and its members have been supportive of efforts to use technology to help deliver electricity safely and reliably to customers. Smart grid technologies, such as synchrophasors, distribution automation technologies, automated controls for voltage and reactive power management, and advanced metering infrastructure, among others, have enabled utilities to: more efficiently transmit electricity; restore power more quickly after outages; reduce peak demand; integrate renewable energy sources; remotely read meters; and reduce operations and management costs. When Congress enacted the Energy Independence and Security Act of 2007 (EISA), APPA was generally supportive of the smart grid provisions included in Title XIII of the legislation.

APPA members have been leaders in the implementation of smart grid technology. Thirty-two public power utilities received funding for Smart Grid Investment Grants from the DOE that were funded by the American Recovery and Investment Act of 2009. Public power utilities have also been leaders in the deployment of distributed energy resources. The relatively small service territories of most public power utilities and their affiliation with local governments have made deployment of such technologies more feasible.

S. 1232, the Smart Grid Act of 2015 seeks to build on the smart grid provisions of EISA by creating a competitive grant program to modernize the electric grid. Grants would fund projects focused on six areas: "fine-tuning energy use based on real-time energy prices; innovating power markets to value new energy technologies; determining new retail electricity structures to account for shifts in energy production and the time-value of energy; energy storage; and smart electric vehicles charging.' It would also direct the DOE to develop standards for data sharing and communications (i.e., interoperability standards) between electric utilities and their customers to improve grid efficiency and reliability. APPA is seeking feedback from its members on the legislation. Preliminarily, APPA has no major concerns with the legislation, but would mention a couple of issues for consideration. First, the Committee should consider amending the language on page 3, lines 4 to 14, to ensure that the Secretary of Energy chooses a sufficient number of utility representatives to the Smart Grid Interoperability Working Group (SGIWG). Ultimately, these technologies are being deployed on the electric grid, which the utility industry understands best. The SGIWG should not be dominated by vendors whose sole interest is in selling goods and services and not to provide safe and affordable electricity. In addition, the language should be amended to ensure that representatives from public power, rural electric cooperative, and investor-owned utilities are selected to participate on the SGIWG. Requiring representation from all three types of electric utilities will ensure that DOE receives input that reflects the diversity of the industry.

In addition, the committee should consider including language that would make it clear that SGIWG would not duplicate the efforts of the already established Smart Grid Interoperability Panel (SGIP). SGIP was established to support the National Institute of Standards and Technology "in its fulfilment of its responsibilities under" EISA.[1] The panel is working with smart grid stakeholders to "accelerate standards harmonization and advance the interoperability of smart grid devices and systems."[2] At a minimum, SGIWG should be required to closely coordinate with SGIP on any recommendations it would make to DOE on establishing or promoting the widespread adoption of interoperability standards.

Another potential area of concern is the grant area focus on rate design for distributed energy. APPA appreciates that the language on page 7, lines 3 through 10, to direct DOE to potentially fund "projects that implement rates, such as 3-part rates, to equitably ensure cost-recovery and the reliability of the distribution grid, while also supporting the increased penetration of distributed generation, storage, and electric vehicles" recognizes the need to ensure cost recovery. Rate design for the integration of distributed generation is a local and state issue, not a federal one. A net-metering approach adopted in one community for rooftop solar, for example, may not be an optimal approach for another community. Congress should not seek to federalize how distributed energy resources are compensated. Rather, Congress should continue to provide or enhance crucial funding for research and development of distributed energy technologies, particularly energy storage technology. The committee should consider adding language to S. 1232 that would make it clear that any rate design projects that receive federal

[1] See SGIP website at http://www.sgip.org/SGIP-History.

[2] *Id.*

funding under this program cannot be the basis for any future federalization of rate design for compensating distributed energy resources.

S. 1233 -- "PURPA's Legislative Upgrade to State Authority Act" or "PURPA PLUS ACT"

APPA opposes this bill as an unnecessary cost burden on consumers.

As discussed above, section 210(a) of PURPA (16 U.S.C. § 824a-3(a)) requires FERC to adopt rules requiring any electric utility to offer to purchase electric energy from a QF. PURPA section 210(b) requires, among other things, that no FERC rule "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."

S. 1233 would amend section 210(b), by appending the following proviso:

> ", except that the rule shall provide that a State regulatory authority or nonregulated electric utility, acting under State authority, may set rates that exceed the incremental cost of alternative electric energy for purchases from any qualifying cogeneration facility or qualifying small power production facility of not more than 2 megawatts capacity".

Thus, the bill would remove the avoided cost cap for QFs with a capacity of not more than 2 megawatts and allow a state—or a non-regulated electric utility such as a public power utility—to set higher rates for mandatory purchases from such QFs.

The putative purpose of the bill is to give states "additional flexibility and authority to be able to incentivize" these small QFs. By definition, these incentive rates would be above avoided cost and displace cheaper, alternative energy—including other, larger QFs. The result would be to increase consumer rates for retail service and distort the QF market. Indeed, it is unclear how rates above avoided cost for this subclass of QFs would be consistent with the other two rate standards of section 210(b)—that such rates "shall be just and reasonable to the electric consumers of the electric utility and in the public interest," and "shall not discriminate against qualifying cogenerators or qualifying small power producers."

S. 1243 – Grid Modernization Act

The bill authorizes $200 million to be appropriated for the non-cybersecurity activities of the Office of Electricity Delivery and Energy Reliability. Specifically authorized are a grid-scale storage research and development program; an advanced distribution system demonstration program; and a demonstration program to develop grid-scale storage with micro-grids. The legislation would also require the Office of Electricity to develop model grid architecture to examine the effects of different combinations of

resources on the grid. Finally, the legislation would amend PURPA to require all covered utilities to incorporate into integrated resource planning consideration of electric grid resilience.

APPA generally has no specific position on the appropriation of funds for specific DOE activities. However, APPA would oppose the proposed addition to PURPA of new section 111(d)(20), requiring the integration of new resilience criteria in integrated plans. Public power utilities fully understand the importance of guarding against damage from all sources to their infrastructure—their poles, wires, substations, transformers, and generating facilities. We also take seriously the growing threat of a cyberattack, which could cause disruptions in the flow of power. Public power utilities have longstanding programs and protocols designed to protect their utility systems. As the sources of threats have increased over the years, public power utilities have planned, prepared, and responded accordingly.

The legislation, however, would require utilities covered by PURPA to incorporate into their integrated resource plan a consideration of electric grid resilience. As part of this consideration, the legislation lists nine separate benefits of grid resilience that the utility must weigh during its resource planning process.

APPA believes that such provisions sidestep the long-standing principal that the federal government should not try to make operational and ratemaking decisions that are best decided at the state and local levels. The provision might not require utilities to incorporate grid resilience into their resource plan, but would require more than 120 public power utilities covered by PURPA to go through the formal process of consideration. To deliberate and then provide proof that each of the nine listed benefits had been considered and then explain the decision to either incorporate or not incorporate resiliency into the integrated plan would be costly, administratively burdensome, and unlikely to result in any net gain in resiliency. These are exactly the sorts of analyses that public power utilities are already conducting. Furthermore, public power utility success in maintaining system reliability would tend to indicate that a federally mandated review of requirements is unnecessary.

Americans for a
Clean Energy Grid

May 13, 2015

The Honorable Martin Heinrich
303 Hart Senate Office Building
Washington, DC 20510

Dear Senator Heinrich:

Americans for a Clean Energy Grid, a project of the Energy Future Coalition, and its supporters and friends welcome your proposed legislation (S. 1017) to provide the Federal Energy Regulatory Commission (FERC) with focused and limited backstop authority to site interstate and interregional transmission lines. Your legislation would revive the clear intent of Congress in the Energy Policy Act of 2005 to provide for such a contingent federal power, enacted by bipartisan majorities in both the Senate and the House, and signed into law by President George W. Bush, but neutered by court decisions finding unintended ambiguities of language. We also welcome your provisions to streamline and enhance the transparency of the federal permitting process – consistent with separate legislation introduced by Chairwoman Murkowski (S.1217). We hope your leadership and initiative will help all to understand that completing such transmission projects in a timely fashion is critical to developing America's vast renewable energy resources and delivering them to customers, and also essential to maintaining an efficient and reliable electric grid.

The U.S. has enough wind and solar energy to power the entire country many times over, but inadequate transmission infrastructure prevents us from tapping the best and most abundant resources in remote areas, far from the cities and towns where most Americans live and work. Timelines of eight to ten years are typical for developing interstate transmission lines, even though large scale wind and solar facilities can be constructed in just one to two years. As a result, our Nation's largest and best clean energy resources remain unable to contribute as they wait for transmission lines to be sited and built.

High voltage transmission is one of the best investments we can make in our economy, our environment and our national security – but it is still far too difficult and time-consuming to build the most urgently needed interstate and interregional lines. The laws and regulations such projects must satisfy were designed for a different era, and under different public policy imperatives. Transmission expansions and upgrades today can consistently deliver benefits exceeding their costs by cutting power prices, eliminating congestion, and slashing the cost of meeting environmental goals. Like the internet, a more robust, reliable, and efficient electric transmission system benefits everyone: consumers, businesses, and the environment.

National infrastructure investments capable of delivering such broad benefits have historically garnered support from Americans in every part of the country and from elected representatives across the political spectrum. We applaud your leadership on this critical issue, see no reason why it should not attract bipartisan support again, and look forward to helping you build that support toward enactment.

Sincerely,

John W. Jimison
Americans for a Clean Energy Grid

Statement for the Record
Bureau of Land Management
Department of the Interior

Senate Committee on Energy and Natural Resources

S. 411, Natural Gas Gathering Enhancement Act
S. 485, Assuring Private Property Rights Over Vast Access to Land Act
S. 1017, Federal Power Act Amendments on Siting Interstate Electric Transmission Lines
S. 1196, Federal Land Access Act
S. 1210, Oil and Gas Production and Distribution Reform Act
S. 1217, Electric Transmission Infrastructure Permitting Improvement Act
S. 1225, Federal Land Asset Inventory Reform Act

May 14, 2015

Introduction

The Bureau of Land Management (BLM) submits the following Statement for the Record for the Committee's hearing on bills pertaining to energy infrastructure on our nation's public lands. Seven of the bills relate to programs administered by the Bureau of Land Management: S. 411, the Natural Gas Gathering Enhancement Act; S. 485, the Assuring Private Property Rights Over Vast Access to Land Act; S. 1017, the Federal Power Act Amendments on Siting Interstate Electric Transmission Lines; S. 1196, the Federal Land Access Act; S. 1210, the Oil and Gas Production and Distribution Reform Act of 2015; S. 1217, the Electric Transmission Infrastructure Permitting Improvement Act; and S. 1225, the Federal Land Asset Inventory Reform Act.

The Department was notified of this hearing only a week in advance, the final list of bills was made available late in the evening on May 7, 2015, and the text of several of the bills was made available a day later, on May 8, 2015. As a consequence, and given the breadth of subject matter contained in the text of the bills, the Administration did not have adequate time to conduct an in-depth analysis and receive input from the many agencies impacted, and the Department did not have sufficient time to develop the detailed, thorough testimony that is appropriate for a hearing on these matters in time for the hearing.

The Department now submits its Statement for the Record.

Background

The BLM is responsible for protecting the resources and managing the uses of our nation's public lands, which are located primarily in 12 western states, including Alaska. The BLM administers more land – over 245 million surface acres – than any other Federal agency. The BLM also manages approximately 700 million acres of onshore Federal mineral estate throughout the nation, including subsurface estate overlain by properties managed by other Federal agencies such as the Department of Defense and the U.S. Forest Service (USFS). That's more than 10 percent of the Nation's surface and nearly a third of its minerals.

The BLM manages this vast portfolio on behalf of the American people under the dual framework of multiple use and sustained yield. This means the BLM administers public lands for a broad range of uses including renewable and conventional energy development, livestock grazing, timber production, hunting, fishing, recreation, and conservation. We manage lands with some of the most significant energy development in the world and some of North America's most wild and sacred landscapes. This unique role often puts the BLM in the middle of some of the most challenging natural resource issues facing our country, from species conservation to advancements in energy extraction. Across the country, we do this work proudly and with a special emphasis on transparency and public processes that incorporate the input and needs of the American people and of the communities in which we live and work.

As part of our mission and in accordance with the President's balanced approach to energy, the BLM is pursuing science-based, environmentally sound development of both renewable and conventional energy resources on the nation's public lands. The BLM's activities provide critical infrastructure and energy for our nation that reduces our reliance on oil, while also protecting our public land and water resources, and providing important recreational opportunities that benefit local economies. The BLM's contribution to the national energy portfolio provides an important economic benefit. The Department collects billions of dollars annually for the Federal Treasury through mineral lease rents and royalties for mineral extraction and other activities, and shares these revenues each year with states, tribes, counties, and other entities. In many states, energy production and other activities are a critical component of the local economy. For example, in fiscal year 2014, onshore Federal oil and gas royalties exceeded $3 billion, approximately half of which were paid directly to the states in which the development occurred. In the same period, tribal oil and gas royalties exceeded $1 billion with all of those revenues paid to the tribes and/or individual Indian owners of the land on which the development occurred.

Federal lands continue to boost domestic energy production in a variety of areas. The BLM works diligently to fulfill its role in securing America's energy future, coordinating closely with partners across the country to ensure that development of conventional and renewable resources occurs in the right places and that those projects are managed safely and responsibly. The BLM continues to make significant efforts in improving how it leases, permits, and provides oversight to all areas of energy development. This includes updating its regulations to reflect current industry practices as well as putting needed technology in the hands of BLM employees. It is one of the BLM's highest priorities to ensure that the operations it authorizes on public and tribal lands are managed in a manner that will protect consumers, human health, and the environment. Secretary Jewell's 2014 mitigation strategy supports this goal by outlining key principles and actions to more effectively offset impacts of large energy development projects on public lands through the use of landscape-level planning. Advancing both development and conservation, the strategy provides greater certainty for project developers with regards to permitting and better outcomes for conservation through more effective and efficient project planning.

Conventional Energy – Secretary Jewell has made it clear that as we expand and diversify our energy portfolio, the development of conventional energy resources from BLM-managed lands will continue to play a critical role in meeting the nation's energy needs and fueling our

economy. The BLM is committed to promoting responsible domestic oil and gas production in a manner that will protect consumers, human health, and the environment. Facilitating the safe and efficient development of these resources is one of the BLM's many responsibilities and part of the Administration's broad energy strategy, outlined in the President's *Blueprint for a Secure Energy Future*. Environmentally responsible development of these resources will help protect consumers and reduce our nation's reliance on oil, while also protecting our federal lands and the environment. As part of this effort, the Department is working with various agencies in support of Executive Order 13604 to improve the performance of Federal permitting and review of infrastructure projects by increasing transparency and predictability of infrastructure permitting and reviews.

In recent years, the BLM has overseen a significant increase in oil production, while also supporting continued natural gas production. Oil production from the Federal and Indian lands where the BLM has permitting and oversight responsibility rose twelve percent in 2014 from the previous year and is now up 81 percent since 2008 – 113 million barrels per year in 2008 to 205 million barrels per year today. For comparison, nationwide oil production over the same period increased 73 percent. The BLM continues to make public lands available for oil and gas development in excess of industry demand.

Oil & Gas Pipelines – The BLM is working hard to do its part to expand the nation's pipeline infrastructure and increase the capacity to transport energy resources when and where it is needed. Oil and gas production is outpacing pipeline capacity and creating bottlenecks in some areas, putting a strain on existing infrastructure. As authorized by Section 28 of the Mineral Leasing Act (MLA), the BLM issues right-of-way (ROW) grants for oil and natural gas gathering, distribution, and transmission pipelines and related facilities. The BLM may grant MLA ROWs on any public lands, or on lands which are administered by two or more Federal agencies, except land in the National Park System and land held in trust for Indian tribes. A designated corridor is a preferred location for the placement of ROWs and the BLM actively encourages use of designated ROW corridors to streamline the authorization process. This minimizes the proliferation of separate ROWs and promotes sharing of ROWs to the greatest extent possible, given considerations of engineering and technological compatibility, national security, and land use planning. Use of existing corridors and sharing of existing ROWs for pipelines protects the quality of natural resources and prevents unnecessary environmental damage to lands and resources.

Since 2009, the BLM has participated in the approval of nine major pipeline expansion projects totaling nearly 2,000 miles of new oil and gas pipeline with nearly 1,050 of those miles crossing Federal lands. In the next 18 months, the BLM is expected to complete review and disposition of four more major pipeline projects totaling approximately 1,000 additional miles with approximately 450 of those miles across Federal lands. Work on these major oil and gas pipeline projects is in addition to the thousands of miles of smaller pipeline projects that are approved every year to transport oil and gas from production sites to the larger gathering and transportation facilities.

Renewable Energy – In the past six years, the BLM has worked to facilitate a clean energy revolution on public lands, approving scores of utility-scale renewable energy generation and

transmission projects. This includes 29 utility-scale solar facilities, 11 wind farms, and 12 geothermal plants, with associated transmission corridors and infrastructure to connect with established power grids. When completed, these projects will provide more than 14,000 megawatts of power, or enough electricity to power about 4.8 million homes, and provide over 20,000 construction and operations jobs. The BLM continues to actively facilitate and support solar, wind, and geothermal energy development on BLM lands.

In 2014, the BLM proposed a rule for competitive leasing in order to promote renewable energy development at appropriate sites in areas that have been determined optimal for wind and solar energy production. Offering lands through a competitive leasing process will allow the BLM to plan smarter by targeting future development toward low-conflict lands close to existing or planned transmission capability. Increased production of renewable energy will create jobs, provide clean energy, and enhance U.S. energy security by adding to the domestic energy supply. The President has established an aggressive goal to increase permitting of new renewable electricity generation capacity on public lands to 20,000 megawatts by 2020.

Transmission Infrastructure – The BLM performs a key role in efforts to strengthen the nation's electric transmission grid. The BLM currently carries the largest portfolio of transmission projects among the nine Federal agencies involved in the interagency Rapid Response Team for Transmission (RRTT). It serves as the lead agency for four of the original seven major RRTT transmission projects. Since January 2009, the BLM has approved 90 major transmission projects (100 kV and larger), totaling over 2,300 miles, 1,600 miles of which cross through BLM lands in 10 western states. From 2012 to 2013 alone, the BLM approved permits which will enable construction of nearly 1,000 miles of transmission lines across Federal lands in seven states. Of 21 currently pending major transmission projects in various stages of environmental review, the BLM is the lead Federal agency for 18. The pending projects total approximately 3,811 miles, with approximately 1,311 miles crossing BLM-managed land. The BLM has undertaken efforts to ensure that the bureau is poised to successfully fill its role as a leader among Federal agencies in the build-out of and upgrade to the nation's electrical grid.

S. 411, Natural Gas Gathering Enhancement Act

S. 411 amends several laws to provide additional authority for the Secretary of the Interior to approve natural gas pipelines and gathering lines on Federal and Indian land. Section 3 of the bill allows the Secretary to approve natural gas pipelines across units of the National Park System. Section 4 of the bill amends the Energy Policy Act of 2005 and adds a new provision (section 319) to categorically exclude from National Environmental Policy Act (NEPA) review certain gas gathering lines and associated field compression units. Under the bill, such lines would be categorically excluded from NEPA review if they are within an area that has a land use plan or environmental document that analyzed transportation of natural gas produced from oil wells as a reasonably foreseeable activity and are located adjacent to or within an existing ROW corridor. The bill's categorical exclusion (CX) is applicable to BLM-managed lands and other Federal lands, and may be applied to tribal lands if requested by an Indian Tribe.

Section 4 of the bill further amends the Energy Policy Act of 2005 and adds a new provision to require the Secretary to conduct a study to identify any actions that may be taken under Federal law or regulation, or changes to Federal law or regulation, to expedite permitting for gas

gathering lines and associated field compression units that are located on Federal land or Indian land. This section requires the Secretary to prepare a report to Congress annually on the progress made in expediting permits for gas gathering lines and associated field compression units that are located on Federal or Indian land and on any issues impeding that progress.

Finally, Section 5 of S. 411 amends the MLA to require the Secretary to issue a sundry notice or ROW for a gas gathering line and associated field compression unit not later than 90 days after receiving the request from the pipeline proponent if the request meets the criteria in Section 4 of the bill, unless the Secretary finds the ROW would violate the Endangered Species Act (ESA) or the National Historic Preservation Act (NHPA).

Analysis

The Department questions the underlying premise of this legislation, as laid out in the findings in section 2. The findings state that "natural gas is lost due to venting and flaring, primarily in areas where natural gas infrastructure has not been developed quickly enough, such as States with large quantities of Federal land and Indian land." They further state that "permitting processes can hinder the development of natural gas infrastructure," and that additional authority for the Secretary to approve natural gas pipelines and gathering lines would "assist in bringing gas to market that would otherwise be vented or flared."

The Department is committed to reducing the venting and flaring of natural gas from oil and gas operations on public lands and is taking steps to address this issue. However, in the Department's experience, the majority of applications to flare gas over the past few years have come from wells that are already connected to pipeline infrastructure. For these wells, a need for new ROWs for pipelines is rarely the factor driving flaring. In addition, the problem of excessive venting and flaring of natural gas is not unique to Federal and Indian lands. In areas where excessive flaring is occurring, the Department finds that the problems stem less from an inability to acquire permits for natural gas gathering lines and more from a lack of desire among producers to prioritize maximizing long-term oil and gas production potential from a given field over short-term profits.

To illustrate this point, the Permian basin in New Mexico is an area where almost all of the producing wells are connected to gas-gathering infrastructure, but substantial flaring still occurs. Similarly, in reviewing applications to vent or flare in North Dakota, the BLM found that out of almost 1,300 applications to vent or flare received between September 2012 and August 2014, about 70 percent were from wells that were already connected to a gas pipeline. For these wells, capturing the gas commonly involves installing additional compressors or expanding a downstream gas processing plant, which do not require a new pipeline, much less approval for a new ROW.

The Department also has grave concerns about the approach prescribed by this bill to expedite and, in some cases, mandate, permitting of natural gas pipelines and gathering lines. S. 411 would exclude gas gathering lines from environmental review, and it would require the Department to approve ROWs across public lands for gas gathering lines, except where approval would violate the NHPA or the ESA. The bill would also allow the Department to permit natural gas pipelines through National Parks. These provisions could significantly limit the

Department's ability to gather relevant scientific and technical information, consider the views of the public, and manage the nation's public lands for multiple uses, as Congress has required under FLPMA. These concerns are discussed in more detail below.

The Department strongly opposes categorically excluding pipeline activities from the requirements for environmental review under NEPA. The BLM is required by law to manage public lands for multiple uses, which necessarily requires understanding and evaluating various uses and values. The environmental review process under NEPA is a critical tool for engaging the public and considering and mitigating impacts to adjacent resources and lands. These open, public processes help the BLM consider impacts on the surrounding communities and the environment, as well as identify unknown or unforeseen issues, which is invaluable to sound public land management. The BLM is committed to providing the environmental review and public involvement opportunities required by NEPA for proposals for the use of BLM-managed lands. S. 411 would prohibit the BLM from engaging in this important process.

The Department also does not believe that these provisions are necessary. The activities called for in S. 411 are already within the scope of existing Department authorities and consistent with our priorities and activities already underway. For example, for an area that has a land use plan or environmental document that includes transportation of natural gas as a reasonably foreseeable activity, the BLM already can, and often does, use its existing authorities to authorize the activity following a determination that the existing NEPA analysis is adequate, provided the necessary site-specific analysis has been conducted and found the action would not cause a significant impact to other resources.

By requiring the Secretary to issue a sundry notice or ROW for a gas gathering system within 90 days of submission, except in limited circumstances, S. 411 would also eliminate the Secretary's existing discretion with respect to these approvals, which is a significant and troubling change from current law. The provision would not allow the Secretary to withhold approval, where appropriate, nor does it contain any requirement for the proponent's request to be fully complete prior to submission. Furthermore, categorical exclusions still require consideration of extraordinary circumstances before they can be applied, even if NEPA analysis is not required, and this consideration may be challenging to complete within the 90-day timeframe.

The Department also strongly opposes the provisions that would authorize the Secretary to permit oil and gas pipelines on National Park Service (NPS) lands – reversing the longstanding prohibition on allowing such pipelines in our national parks (except where Congress adopts an explicit authorization). In its 1973 amendments to the MLA, Congress determined that our national parks would not be subject to the general ROW provisions. This specific exemption in the MLA protects the integrity, resources, and values of the National Park System. The significant infrastructure associated with the clearing, grading, trenching, stringing, welding, coating and laying of pipeline as well as the transportation of oil and gas products via pipeline, which carries the risk of oil spills and gas explosions, is inconsistent with the conservation mandate set forth in the NPS Organic Act. S. 411 would overturn longstanding and necessary protection of park system resources and values, visitor experience, and human health and safety.

The Department has concerns that the provisions of Section 4, which apply to Tribal land, may conflict with the agency's legal responsibility for consultation, stewardship and oversight under the Indian Mineral Leasing Act of 1938.

The Department also has concerns about the requirement to conduct a study to identify proposed changes to Federal law or regulations and to report annually on progress in expediting permitting for gas gathering lines and associated field compression units that are located on Federal land or Indian land and impediments to that progress. If enacted, these requirements would divert limited BLM resources from oil and gas permitting, issuance of ROWs, and inspection and enforcement activities, undermining the goals of this legislation.

The Department is also concerned that S. 411's provisions could be interpreted to authorize the Secretary to issue a permit for oil and gas pipelines on lands that are a component of the National Wilderness Preservation System, a concept the Department strongly opposes.

S. 485, Assuring Private Property Rights Over Vast Access to Land Act

S. 485 amends Section 1222 of the Energy Policy Act of 2005 to prohibit the Secretary of Energy from using eminent domain to site an electric transmission facility on private land unless both a state's governor and the head of a public utility district explicitly approve the action, and for projects that would affect the land of an Indian tribe, the head of the governing body of that Tribe. The bill also requires the Secretary of Energy to site electric power facilities, to the maximum extent practicable, on an existing federal ROW or on federal land managed by the BLM, USFS, Bureau of Reclamation, or Army Corps of Engineers.

Analysis

The only provision in S. 485 applicable to the BLM is the bill's direction that electric transmission projects be sited on federal lands to the maximum extent practicable; the Department defers to the Department of Energy on other provisions of the legislation. The Department of Energy notes that it has never acquired land under the Section 1222 program, and use of eminent domain would be a last resort. S. 485 would put unusual conditions on the use of federal eminent domain authority that other agencies do not face. To the extent Section 1222 was intended to overcome state opposition to interstate transmission development in the public interest, S. 485 would undermine that goal by allowing individual states to prevent the use of federal eminent domain authority.

The BLM has concerns that S. 485 may impact the Bureau's ability to effectively site interstate electric transmission facilities. The transmission infrastructure at issue in S. 485 is critical to the new energy economy and the BLM manages public lands for multiple uses, which may include, where appropriate, the siting of electric transmission lines under ROW grants. Additionally, transmission line segments that cross state or private land are permitted under each state's transmission siting authority which is a separate process from the federal permitting process. The BLM believes that, regardless of land status, transmission projects should be sited in existing transmission corridors, co-located with existing transmission infrastructure, or located in areas with the least environmental impact.

S. 1017, Federal Power Act Amendments on Siting Interstate Electric Transmission Lines
S. 1017 amends the Federal Power Act concerning the siting of interstate electric transmission facilities. Under the bill, if a state fails to approve a proposed high-priority regional electric transmission project within one year of its application, the Federal Energy Regulatory Commission (FERC) would be authorized to approve the siting and construction despite the state's failure to act. FERC would grant a certificate to the proponent of a high-priority regional transmission project for the construction and operation of the whole electric transmission facility, including the use of eminent domain on private lands. If the facility crosses federal lands, S. 1017 directs FERC to seek from federal resource agencies recommended mitigation measures based on habitat protection, environmental considerations or cultural site protection, and to incorporate those recommended mitigation measures in the certificate unless FERC finds them to be infeasible or not cost-effective for the proponent. As to Indian lands, S. 1017 requires certificate holders to comply with federal requirements for obtaining a ROW over Indian land.

Analysis
The BLM has concerns that S. 1017 may not preserve the Bureau's authority to site interstate electric transmission facilities on public lands. The BLM authorizes ROW on federal lands for a variety of uses including electric transmission lines under Title V of the Federal Land Policy and Management Act (FLPMA). The BLM understands it is the sponsor's intent that when an interstate electric transmission facility traverses federal lands, it should comply with federal environmental, land, and resource management laws. As currently drafted, the legislation is unclear as to the impact of a FERC certificate for the whole electric transmission facility on the BLM's current authorities to review and grant ROW for electric transmission facilities on public lands. For example, although the legislation requires a certificate holder to comply with federal requirements for obtaining a ROW over Indian land, the bill lacks similar language for a ROW over federal land. The BLM would like to work with the sponsor and the Committee on language to assure that moving forward, any legislative language considered by the Committee would facilitate a timely and effective transmission siting process on both federal and Indian lands.

In addition, the BLM would like to discuss with the sponsor and the Committee the extent to which S.1017 may conflict with the 2009 interagency Memorandum of Understanding (MOU) among the Departments of Agriculture, Commerce, Defense, Energy, and the Interior, and the EPA, Council on Environmental Quality, FERC, and Advisory Council on Historic Preservation on Coordination in Federal Agency Review of Electric Transmission Facilities on Federal Land. This interagency MOU sets out a coordination and review process among these agencies and has been helpful in resolving differences related to siting and approval of these transmission facilities.

S. 1196, Federal Land Access Act
S. 1196 amends the MLA to include the National Park System in the definition of federal lands under the Act. Under the bill, the Secretary would be authorized to approve ROW grants within the National Park System for oil and natural gas gathering, distribution, and transmission pipelines and related facilities.

Analysis

The Department strongly opposes S. 1196 as it would reverse the longstanding prohibition on allowing such pipelines in our nation's national parks unless explicitly authorized by Congress. In its 1973 amendments to the MLA, Congress determined that such lands would not be part of the general ROW provisions. This specific exemption in the MLA protects the integrity, resources, and values of the National Park System. The significant infrastructure associated with the clearing, grading, trenching, stringing, welding, coating and laying of pipeline as well as the transportation of oil and gas products via pipeline, which carries the risk of oil spillage and gas explosions, is inconsistent with the conservation mandate set forth in the NPS Organic Act. S. 1196 would overturn longstanding and necessary protection of park system resources and values, visitor experience, and human health and safety and would undermine the very purpose for which National Park System units were created.

The Department is also concerned that S. 1196's provisions could be interpreted to authorize the Secretary to issue a permit for oil and gas pipelines on lands that are a component of the National Wilderness Preservation System, a concept the Department strongly opposes.

S.1210, Oil & Gas Production & Distribution Reform Act

S.1210 requires the Federal Energy Regulatory Commission (FERC) to coordinate the regulatory activities of federal, state, and local governmental agencies in their review of an application for an oil and gas pipeline. The bill requires FERC to identify all governmental entities with responsibility for reviewing any aspect of an oil and gas pipeline application and to track and post the status of the various governmental reviews on the pipeline application. S. 1210 establishes deadlines for federal agencies to issue permits associated with the pipeline application – 90 days after FERC issues its final environmental document – and requires each agency considering an aspect of federal authorization to carry out its reviews concurrently, as well as in conjunction with reviews under NEPA. The bill requires federal agencies to defer to FERC's determination of the appropriate scope of environmental analysis.

Analysis

The Department of the Interior opposes S. 1210 and its insertion of FERC into the current process under the MLA for granting oil and gas pipeline ROWs across federal lands. This existing MLA process effectively facilitates responsible oil and gas development and distribution while protecting natural resources on federal lands, and provides for coordination with state and local governments and basic public review and input. The Department notes that an additional layer of interagency coordination has the potential to in fact complicate reviews and delay authorizations. The Department objects to the bill's provision which requires federal agencies to defer to FERC's determination of the appropriate scope of environmental analysis. Such deference would deny BLM and other land management agencies – whose missions are distinct from FERC's – the opportunity to do the NEPA analysis required and to conduct the degree of public outreach that it deems necessary. This may have the unintended consequence of forcing agencies to deny applications that would otherwise be acceptable under full environmental review.

S. 1217, Electric Transmission Infrastructure Permitting Improvement Act

S. 1217 establishes the Inter-agency Rapid Response Team for Transmission (RRTT) to expedite the permitting process for electric transmission infrastructure, as well as maintenance and

upgrades, on both Federal and non-Federal land. The team would be comprised of representatives of FERC; the Departments of Energy, the Interior, Defense, Agriculture, and Commerce; the Council on Environmental Quality; the Advisory Council on Historic Preservation; and the Environmental Protection Agency. Among other responsibilities, the team would facilitate coordination and unified environmental analysis between project applicants, Federal agencies, States, and Indian tribes involved in the transmission siting and permitting process. The team would also submit an annual report on regionally and nationally significant electric transmission projects to the Congress. The bill further requires FERC to establish a Transmission Ombudsperson position and amends the FLPMA to limit the authority of the Secretary of the Interior regarding electric transmission ROWs reserved for the use of Federal agencies and departments.

<u>Analysis</u>
The Department supports the goal of coordinating the permitting of electric transmission projects among Federal agencies and other stakeholders, and currently engages in coordination similar to that envisioned by S. 1217 through an existing RRTT and interagency efforts under section 216(h) of the Federal Power Act. It is unclear how S. 1217 affects the existing framework under section 216(h). We are concerned also by the lack of any definitions specifying the types or categories of projects the Inter-agency Rapid Response Team for Transmission would coordinate. The Department would like to work with the Committee to ensure that the team's efforts are focused on large-scale projects involving new or upgraded electric transmission infrastructure, as opposed to smaller projects such as maintenance. Since maintenance actions may not require specific approvals and are often localized in nature, we believe local oversight would be preferable to that of a large interagency team. In addition, the Department opposes the amendment of FLPMA as proposed in S. 1217. This provision would curtail the Secretary's management discretion with respect to certain existing ROWs, including some issued prior to enactment of FLPMA and NEPA. The Department and representatives of the federal Power Marketing Administrations (PMAs) under the Department of Energy would like to work with the Committee to ensure the bill allows the PMAs to maintain critical infrastructure while allowing the Department to address changing environmental issues.

<u>S. 1225, Federal Land Asset Inventory Reform Act</u>
S. 1225 requires the Secretary of the Interior to develop and maintain a multipurpose cadastre of all Federal real property, defined as real estate "consisting of land, buildings, crops, forests, and other resources." The cadastre would be made publicly available on the Internet in a graphical, geospatially enabled, and searchable format. It would also identify all land and parcels identified as potentially suitable for disposal in Resource Management Plans (RMPs). The bill defines cadastre as an inventory of the real property of the Federal government including information about the "natural or man-made physical features, phenomena, or boundaries." The bill further requires the Secretary to determine which properties "can be better managed through ownership by a non-Federal entity," and to prevent the disclosure of any parcels, buildings, or facilities if the disclosure would impair or jeopardize national security or homeland defense.

According to the Congressional Research Service, the Federal government manages 635 to 640 million acres of the nearly 2.3 billion acres that constitute the United States. The largest land managers for the Federal government are the Departments of the Interior, Agriculture, Defense,

and Energy. Within the Department of the Interior, the Bureau of Land Management administers approximately 245 million acres; the National Park Service manages approximately 80 million acres; the Fish and Wildlife Service manages approximately 150 million acres as part of the Refuge System; and the Bureau of Reclamation manages approximately 6.5 million acres associated with Bureau of Reclamation projects. Within the Department of Agriculture, the USFS manages approximately 193 million acres. Approximately 27.9 million acres in the United States are managed by the Department of Defense. In addition to these lands, the same agencies and many others manage hundreds of thousands of buildings and structures.

Analysis

The Department has serious concerns with S. 1225, which would provide little new critical information about the lands the Federal government manages and would be prohibitively expensive to implement. The cost of this type of a detailed inventory of Federal real property called for in S. 1225 would be exorbitant. A very rough estimate suggests that the cost could run in the many billions of dollars. Some of the requirements in S. 1225 are duplicative of other work and reports done by Federal agencies. One example is a comprehensive review of the Federal government's oil and gas resources which was required by the Energy Policy Conservation Act of 2000 (EPCA), Public Law 106-469. The final phase of the multi-agency EPCA report was completed in 2008. S. 1225 also requires that as part of the cadastre, a review be done to determine which lands could be better managed by a non-Federal entity. For the BLM, for instance, this would be a costly process that would duplicate work already being done by individual BLM field offices.

Many of the decisions about how best to manage the public lands entrusted to the BLM's management are made through 157 individual RMPs which are developed with full public participation at the local level. These RMPs provide the foundation for every on-the-ground action taken or authorized by the BLM, and include an inventory and assessment of a broad range of resource values and public land uses in a particular area. Among the many decisions made through the RMP process is the identification of lands that are potentially available for disposal. Extensive public involvement in this process is critical. S. 1225 appears to substitute the judgment of officials in Washington, D.C. for decisions made on the ground by local field managers, through an open and inclusive public process. The Department has serious concerns with S. 1225 because of the likely costly and duplicative process of identifying lands for disposal established by this bill.

The Department of the Interior is aware of and appreciates the concerns expressed by some Members of Congress about the accuracy of data on lands owned by the Federal government and specifically in the Department of the Interior. It is worth noting that the Federal government is making important strides in improving the accuracy, efficiency and level of data available on the Federal real property portfolio. The Federal Real Property Council (FRPC) works across agencies to determine opportunities to spread real property best practices, achieve short and long-term cost savings, and realign real property inventories to agency mission and service delivery.

Beginning, in 2010, the BLM initiated a mineral and land records verification and validation program which focused on delivering accurate land inventory data, while improving

transparency and accountability. This enhancement program continues with available funding and the leveraging of other sources of land information which allows for more efficient and effective management of mineral and land records. The public can continue to access updated land management data sets through the BLM's current and future websites.

The cost of the comprehensive inventory of Federal lands envisioned by S. 1225 would be prohibitive. The Department of the Interior believes that the redirection of funds away from accomplishing important projects and the jobs they create in areas of energy development, resource protection, recreation, and conservation is not the best use of taxpayer dollars.

Statement for the Record
Senator Bill Cassidy, M.D.
Hearing on Energy Infrastructure Legislation

May 14, 2015

Madam Chairman, thank you for holding this hearing and providing a venue to highlight the great importance energy infrastructure plays in determining our energy security and success of this country.

The State of Louisiana has over 19,000 miles of pipeline across the state that helps provide for the energy needs of Louisianans and all Americans. Louisiana is unquestionably one of the most energy rich states in the country and the oil and gas that is produced both on and offshore moves across the country through Louisiana's energy infrastructure to meet the needs of consumers around the United States.

Louisiana's 19 oil refineries account for nearly one-fifth of the nation's refining capacity and are capable of processing more than 3.2 million barrels of crude oil per calendar day. With regard to natural gas, Louisiana has five natural gas marketing centers. The most active natural gas market center in North America is the Henry Hub in Erath, Louisiana, where nine interstate pipelines and four intrastate pipelines interconnect to provide natural gas to major markets throughout the country. Many Gulf States, including Louisiana, are net exporters of oil and natural gas. As our energy needs continue to grow, it is vital that we have a responsive system in which our energy infrastructure can flourish and meet demand.

Unfortunately, viable infrastructure projects have been stalled because of outdated regulations and puzzling interpretations of existing laws. Today, we have the opportunity to start to remedy many of these issues and streamline the processes so that energy infrastructure projects are approved in a timely manner. I would like to bring to the committee's attention two bills that I authored with my colleagues in order to fix some of the issues that energy infrastructure projects have encountered. It is imperative that we repair these processes, so that energy infrastructure is able to meet the growing needs of our citizens and economy.

S. 1210, the Oil and Gas Production and Distribution Reform Act

America's oil and natural gas production is increasing, yet there is a shortage of pipelines to support moving these natural resources to areas of high demand. The current permitting process for pipelines often takes months or years. The slow and uncertain regulatory approval process delays construction, which delays manufacturing projects and hurts families and businesses that rely on affordable energy.

Domestic energy production is accelerating, but the approval process to build the infrastructure to move this energy is stuck in neutral. Streamlining the approval process saves taxpayer money and ensures Americans have access to reliable energy to fuel their cars, heat their homes and run their businesses.

The *Oil and Gas Production and Distribution Reform Act* requires the Federal Energy Regulatory Commission (FERC) to approve or deny an application within 1 year of receiving a complete application that is ready to be processed.

The agency then responsible for issuing any federal approval must approve or deny issuance within 90 days following FERC's review. If the agency fails to approve or deny issuance of a permit, license, or approval within the prescribed time-frame (90 days or 120 days if an extension is granted), the license, permit, or approval shall take effect 30 days after the applicable application time period.

S. 1196, the Federal Land Access Act

The *Federal Land Access Act* would amend the *Mineral Leasing Act* to allow the Secretary of the Interior to grant rights-of-way for natural gas pipelines that travel across National Park Service land. Natural gas pipelines were not common when these statues were enacted in the early 20th century and regulations have failed to keep up with technological advances to the determent of our energy infrastructure. Natural gas pipelines were not intentionally excluded from the right-of-way process and consumers should not have to pay an additional energy cost premium because of a technicality. In fact, until the 1980s, natural gas pipeline projects were included in the rights-of way process because the Department of the Interior deemed that they had the authority to do so based on the spirit of the law.

Current regulatory constraints forbid these rights-of-ways from occurring without project-specific legislation by Congress. The current burdensome process has caused unnecessary delays, and in some cases, inconsistent outcomes. Many projects have waited years for Congressional action only to have to wait even longer for the Department of Interior to make their final determination. This legislation removes unnecessary restrictions and creates a sensible streamlined process that will not adversely affect any Department of Interior environmental review process.

This legislation would continue the original intent of the rights-of-way process by allowing the Secretary of the Interior to disseminate authorization. More certainty in the process will unleash our energy infrastructure to keep pace with the growing energy needs of our country.

Thank you, and I yield back.

DCA
DISTRIBUTION CONTRACTORS ASSOCIATION

May 12, 2015

The Honorable Lisa Murkowski
Senate Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Chairman Murkowski,

The Distribution Contractors Association (DCA) represents contractors, suppliers and manufacturers who provide construction services including installation, replacement and rehabilitation of natural gas pipelines. DCA applauds your efforts to advance comprehensive energy legislation during this Congress, and we encourage you include provisions to modernize the current permit process for natural gas pipelines in the bill considered by the Senate Energy and Natural Resources Committee.

Legislation (S 1210) sponsored by Sens. Capito, Hietkamp and Cassidy would require cooperation from all federal and state agencies involved in a pipeline application, including setting firm deadlines for the issuance of permits. The bill would also require concurrent reviews by state and federal agencies in conjunction with National Environmental Policy Act (NEPA) reviews.

Pipeline projects create high-paying jobs, generate significant economic activity and expand the tax base in local communities. Hundreds of thousands of workers are employed to explore, produce, transport and distribute natural gas, and industry studies show that every $1 billion invested in underground infrastructure creates up to between 25,000 and 30,000 jobs and increases demand for products and services in other industries.

According to a 2014 report by the INGAA Foundation, approximately 850 miles in new gas transmission pipelines and over 800 miles of new laterals to/from power plants, processing facilities, and storage fields will be needed every year from 2011 and 2035. The current permitting process exacerbates this situation. Key pipeline projects are often stalled because of delays in acquiring federal and state permits and rights-of-way approvals from various regulatory agencies. These delays increase costs and lead to missed in-service dates and displacement of workers, neglecting the strong economic benefits that come with pipeline construction projects.

DCA supports legislative efforts to streamline the permitting process in order to get important projects off the ground. We thank you for your continued leadership on this important issue.

Sincerely,

Robert Darden
Executive Vice President

The Honorable Cory Gardner
Statement for the Record
U.S. Senate Committee on Energy and Natural Resources
To receive testimony on several energy infrastructure bills
May 14, 2015

Thank you Chairwoman Murkowski, Ranking Member Cantwell, and the other members of the committee for the opportunity to submit a statement for the record. The subcommittee on East Asian, the Pacific, and International Cybersecurity Policy on the Senate Foreign Relations Committee is having its first hearing, and because I am the Chairman of the subcommittee I will be unable to attend today's hearing.

This energy hearing is another important step towards the comprehensive energy bill that we are working on this Congress. It is my hope that the committee engages in meaningful discussions on these twenty-two infrastructure bills in order to gain a stronger perspective on what federal infrastructure policies need updated to meet current energy demands. Our infrastructure should accommodate the increase in domestic natural gas production, and the integration of intermittent resources, among others.

Once again, thank you for the opportunity to submit a statement for the record. I look forward to working with members of the committee in a bipartisan fashion on our energy infrastructure needs.

GAS PROCESSORS ASSOCIATION

MIDSTREAM'S GREATEST RESOURCE

May 13, 2015

The Honorable John Barrasso
United States Senate
307 Dirksen Senate Office Building
Washington, D.C., 20510

The Honorable Heidi Heitkamp
United States Senate
110 Senate Hart Office Building
Washington, D.C., 20510

Dear Senators Barrasso and Heitkamp:

GPA is the leading organization advocating for midstream operations. GPA has served the U.S. energy industry since 1921 as a non-profit trade association composed of 122 midstream energy companies that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead, as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane and natural gasoline. GPA members account for more than 90 percent of the NGLs produced in the United States from natural gas processing. Gathering lines are the essential mode of transportation for GPA members operations who represent at least 85,197 direct jobs. GPA members processed approximately 50 billion cubic feet per day of natural gas in 2013, produced 937,591,000 barrels of NGLs in 2013, and own or operate at least 470 natural gas processing plants in the United States.

We want to thank you for your leadership on S.411, the *Natural Gas Gathering Enhancement Act*. This bill would set deadlines for, and expedite the permitting of, natural gas gathering lines located on federal land and Native American land. We recognize that the siting of natural gas gathering lines located on federal land and Native American land can be challenging due to permitting delays. Depending on the needed infrastructure, an inability to obtain required rights-of-way permits on federal or Native American lands can lead to venting and flaring of oil and gas wells whether or not the wells are located on federal land or Native American land. Expediting right-of-way permits on federal and Native American lands for natural gas gathering lines will reduce the need for venting and flaring and would thereby reduce emissions. Furthermore, expediting permits will increase economic development, provide a safe mode of transportation, and provide the needed energy infrastructure that is critical to ensuring America's energy security.

GPA supports S. 411 but believes the bill can be enhanced with two needed additions. We believe that these additions would be in line with the intent of the proposed legislation. The first is editing the definition of "gathering lines" to include all the lines that may be used for gathering. Specifically, our members frequently run up to three lines in their gathering line systems, one for natural gas, one for water, and one for oil. Our members need all three lines for their processing operations. Any effort to improve permit streamlining for natural gas operations on federal land and Native American lands would need to include all three lines for the permit streamlining to have the most impact since all three lines are needed for a gas

gathering system. The second edit we would suggest is improving the bill to make the term "compressor" plural. A number of our gathering systems run on multiple compressors so leaving the term "compressor" singular could potentially only address a portion of a gathering line.

Please feel to contact me at (202)279-1664 or mhite@gpaglobal.org should you have any questions or comments regarding the GPA's requested additions to S.411.

Respectfully submitted,

Matthew J. Hite

Matthew J. Hite
Vice President of Government Affairs
Gas Processors Association

GRIDWISE ALLIANCE

May 13, 2015

The Honorable Maria Cantwell
511 Hart Senate Office Building
Washington, DC 20510

Dear Senator Cantwell:

The GridWise Alliance (GWA) applauds your continued leadership on grid modernization issues, and commends you for having authored and introduced "The Grid Modernization Act of 2015." GWA consists of electric utilities, information and communications technology equipment and service providers, national laboratories, academic institutions, Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), and more. Our Washington State-based members include Itron, Alstom, Pacific Northwest National Laboratory, and the Bonneville Power Authority.[1]

The electric grid is critical to all aspects of our daily lives, yet it resembles the same system that was in place nearly 100 years ago. We face a pressing need to bring our electric system into the twenty-first century to meet the changing demands of our digital economy.

Your bill adopts a comprehensive approach toward modernizing our electric infrastructure. If enacted, "The Grid Modernization Act of 2015" would play a vital role in facilitating the transformation to the future electric grid. Specifically, this legislation would: establish a national policy that sets a clear and ambitious 'vision' to achieve the future grid, provide metrics to measure and track the progress toward achieving this goal, create demonstration projects, and offer states the tools and technical assistance they will need as the electric system evolves to help them develop associated policy and regulatory changes. As a result, it would help integrate a range of distributed energy resources, including storage, microgrids, and electric vehicles, into the grid, and would drive increased security, resilience, reliability, and optimization of the entire electric system. In addition, your legislation would empower consumers to better manage their energy usage.

The GridWise Alliance looks forward to working with you, all Members of this Committee, and with the full Senate to continue to help advance these important and timely goals.

Sincerely,

Becky Harrison

Becky Harrison
CEO
GridWise Alliance

[1] National laboratories, RTOs/ISOs, and BPA do not participate in advocacy/lobbying activities.

GRIDWISE ALLIANCE

May 13, 2015

The Honorable Mazie Hirono
330 Hart Senate Office Building
Washington, DC 20510

Dear Senator Hirono:

The GridWise Alliance (GWA) commends you for having introduced "The Next Generation Electric Systems Act."

GWA consists of electric utilities, information and communications technology equipment and service providers, national laboratories, academic institutions, Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), and more.[1]

Your bill would stimulate the array of collaboration and innovation that we need to experience the transformation to the "Grid of the Future," looking out years, if not decades, from now, to ensure we achieve this goal. It would bring together the diversity of public and private, including federal, Tribal, state, and local, stakeholders that are essential to achieving the innovation and vision required of this complex and substantial effort.

This program also would help leverage and optimize federal and private sector investments with one another. Finally, the public-private collaborations that would be driven by your bill would help drive economic growth, strengthen our global competitiveness, and create highly-skilled jobs.

The GridWise Alliance looks forward to working with you, all Members of this Committee, and with the full Senate to continue to help advance these important and timely goals.

Sincerely,

Becky Harrison

Becky Harrison
CEO
GridWise Alliance

[1] National laboratories, RTOs/ISOs, and BPA do not participate in advocacy/lobbying activities.

HEAT IS POWER LET'S CAPTURE IT

WHP Waste Heat to Power

June 18, 2015

The Honorable Lisa Murkowski, Chair
Committee on Energy and Natural Resources
U.S. Senate
709 Hart Senate Office Building
Washington, DC 20510

The Honorable Maria Cantwell, Ranking Member
Committee on Energy and Natural Resources
U.S. Senate
511 Hart Senate Office Building
Washington, DC 20510

From: The Heat is Power Association

Re: May 14 Hearing on Energy Infrastructure Legislation, S. 1037

Dear Chairman Murkowski and Ranking Member Cantwell:

As the Senate Committee on Energy and Natural Resources develops a bipartisan energy package, the Heat is Power Association urges you to oppose S.1037 which could eliminate requirements for utilities to purchase power from qualifying facilities under the Public Utilities Regulatory Policies Act (PURPA). This proposal would be a set back to the deployment of waste heat to power (WHP) facilities.

WHP uses waste heat from industrial processes to generate electricity with no additional fuel, combustion, or emissions, turning industrial waste heat into a resource for clean electricity generation and an economic driver for global competitiveness. WHP can help address critical public policy objectives related to increasing industrial efficiency and reducing emissions of greenhouse gases and criteria pollutants. In fact, WHP is defined as a renewable energy source in seventeen state renewable portfolio standards for many of the reasons stated above.

We appreciate the Committee's efforts to make the nation's energy sector more efficient. We hope that the forthcoming energy package will preserve provisions in PURPA under section 210(m) that require utilities to purchase power from qualifying WHP facilities that do not have nondiscriminatory access to markets and services, so that the nation can continue to benefit from these technologies.

Sincerely,

Susan Brodie
Executive Director

The Heat is Power Association (HiP) is the trade association for the waste heat to power (WHP) industry. WHP uses waste heat from industrial processes to generate electricity with no additional fuel, no combustion, and no incremental emissions. HiP educates decision makers about clean energy from waste heat and lobbies for policies that provide parity for WHP with other sources of emission-free power like wind, solar and geothermal.

The Heat is Power Association • 2215 S York Road, Suite 202, Oak Brook, IL 60523 • heatispower.org • 630.292.1304

HEAT IS POWER
LET'S CAPTURE IT

WHP

✓

The Honorable Jean Shaheen
506 Hart Senate Office Building
Washington, D.C., 20515

May 28, 2015

Dear Senator Shaheen,

The Heat is Power Association (HiP), the trade association for the waste heat to power (WHP) industry, wishes to express our appreciation for your sponsorship of the Heat Efficiency through Applied Technology (HEAT) Act and the Clean Distributed Energy Grid Integration Act. We believe the HEAT Act, which would improve interconnection procedures and tariff schedules, as well as standards for supplemental, backup, and standby power fees for WHP projects, is a great step toward bolstering this clean power source. The Clean Distributed Energy Grid Integration Act would advance the integration of clean distributed energy, including WHP, into electric grids.

As you know, WHP uses waste heat from industrial processes to generate electricity with no additional fuel, combustion, or emissions, turning industrial waste heat into a resource for clean electricity generation and an economic driver for global competitiveness. WHP can help address critical public policy objectives related to increasing industrial efficiency and reducing emissions of greenhouse gases and criteria pollutants. In fact, WHP is considered a renewable energy source in seventeen state renewable portfolio standards for many of these reasons.[1]

A recent DOE report estimates 15,000 MW of emission-free electricity could be generated in the U.S. from industrial waste heat, spurring the creation of thousands of jobs and millions of dollars of investment to make American businesses cleaner and more energy efficient.[2] Improving interconnection, backup and standby procedures, fees, and grid integration for clean distributed energy will help the U.S. realize its clean electric generation potential and spur investments in manufacturing competitiveness.

We thank you for your leadership and look forward to working with your staff to help ensure both the HEAT Act and The Clean Distributed Energy Grid Integration Act become law.

Sincerely,

Susan Brodie
Executive Director, Heat is Power Association

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[1] Catalog of States in Which Waste Heat to Power is Provided Incentives in Renewable Energy and Energy Efficiency Policies and Programs, The Heat is Power Association, November 2014.
[2] Waste Heat to Power Market Assessment, ICF for Oak Ridge National Lab, March 2015, http://www.heatispower.org/wp-content/uploads/2015/02/ORNL-WHP-Mkt-Assessment-Report-March-2015.pdf

The Heat is Power Association (HiP) is the trade association for the waste heat to power (WHP) industry. WHP uses waste heat from industrial processes to generate electricity with no additional fuel, no combustion, and no incremental emissions. HiP educates decision makers about clean energy from waste heat and advocates for policies that provide parity for WHP with other sources of emission-free power like wind, solar and geothermal.

The Heat is Power Association 2215 S York Road, Suite 202 Oak Brook, IL 60523 www.heatispower.org

Statement on S. 1017, Siting of Transmission Lines
Senator Martin Heinrich
May 14, 2015

Thank you for holding this hearing on energy infrastructure.

I'd like to say a few words about the bill I introduced, S. 1017, which is a simple update of the existing federal role in siting electric transmission lines.

This committee first provided FERC so-called "backstop" siting authority in EPAct05 (signed by then-President Bush); however, for a variety of reasons that approach has proven to be non-workable.

The Energy Committee then reported a bipartisan bill in 2009 that attempted to address some of the problems in the 2005 act, but the full Senate never considered the legislation.

My bill is simply an update of the very narrow authority Congress provided to FERC in 2005 to approve and site new priority electric transmission lines.

FERC's limited authority to site transmission lines would apply only in the case of a project included in a regional transmission plan that has been developed as part of a regional transmission planning process as currently required by FERC's Order 1000. This siting authority would only be available to regional transmission projects that serve multiple entities and where the costs are to be shared among the entities

As under current law, developers of transmission projects must first continue to seek approval from local or state authorities to site and construct the project.

The bill authorizes FERC to step in and provide backstop siting authority only if local or state approval is not provided within one year or in cases where a state does not have legal authority to consider or approve a project under state law.

In this unlikely case, a transmission developer may ask FERC for backup authority to site and construct the priority regional transmission line.

The commission would be required to conduct a full public process to review the project and perform all required federal authorizations, such as those under the National Environmental Protection Act and for the use of any federal lands.

I think my colleagues know that under the Natural Gas Act of 1938, FERC has long been responsible for siting interstate natural gas transmission pipelines.

Meanwhile, the Federal Power Act is now 80 years old and increasingly limiting the full development of robust regional markets for electric power.

Our system of power transmission and federal regulation were designed for an era that no longer exists. Today's interconnected transmission network with regional transmission operators, independent power producers, distributed generation, and energy storage are using the grid in a way no one foresaw just a decade ago.

I believe my bill represents a very simple update to existing law, and I look forward to working with the committee on modernizing our nation's electric grid.

I ask consent that letters from WIRES and Americans for a Clean Energy Grid be included in the record.

Senator Mazie K. Hirono

Statement for the Record
Committee on Energy and Natural Resources
Hearing on Energy Infrastructure Legislation
May 14, 2015

I thank the Chair for including in today's hearing a bill I introduced, the Next Generation Electric Systems Act, S. 1207. The bill directs the Secretary of Energy to establish a competitive grant program to develop and carry out projects related to transformation of the electric grid. The bill is intended to provide incentives to bring together expertise from the public and private sectors in order to jointly drive innovation in grid technologies, including the ability of the electric power grid to provide affordable and reliable electricity from increasingly clean energy sources.

Hawaii is on the leading edge of a nationwide transformation of the electric system that, as we heard in testimony from Ms. Ericson today, "will create opportunities to enhance the reliability, efficiency, resiliency, and flexibility of the electric system, and strengthen our global competitive advantage." The competitive grant program established by the Next Generation Electric Systems Act would help electric systems in Hawaii and across the country seize opportunities to accommodate additional renewable sources, energy storage systems, and distributed generation with a focus on delivering affordable and reliable service to communities.

The program would be open to a broad range of projects that would help foster innovative solutions to the biggest challenges posed by grid modernization. The project types include: optimal design of the electric grid and electricity delivery systems; integration of energy storage, electric vehicles, microgrids, energy efficiency, and demand response programs; integration of telecommunications and information technologies to support management of the electric system; and efforts to determine the technological, regulatory, business model, and market barriers to transforming the electric grid.

The grants would be open to partnerships of two or more entities including universities and colleges, electric utilities, State or local governments, Indian tribes, national laboratories, technology companies, regional transmission organizations, and other entities.

Proposals from two or more partnerships would be selected by the Secretary of Energy based on the recommendations of a committee of technical experts and reflecting geographic diversity, degree of innovation, level of consumer benefits, opportunities for cost-sharing, and other factors.

To improve the performance and efficiency of the electric grid, I ask that the Committee include the Next Generation Electric Systems Act in any broader energy legislation it produces.

I would also ask to submit for the record a letter of support for S. 1207 from the GridWise Alliance, a group with membership from a broad range of the energy sector.

INTERNATIONAL DISTRICT ENERGY ASSOCIATION

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Phone (508) 366-9339
Fax (508) 366-0019
idea@districtenergy.org
www.districtenergy.org

May 20, 2015

The Honorable Lisa Murkowski
Chairman
U.S. Senate Committee on
Energy & Natural Resources
709 Hart Senate Office Building
Washington, D.C. 20510

The Honorable Maria Cantwell
Ranking Member
U.S. Senate Committee on
Energy & Natural Resources
511 Hart Senate Office Building
Washington, D.C. 20510

Dear Chairman Murkowski and Ranking Member Cantwell:

We are writing to express our support for the Clean Energy Grid Integration Act (S. 1201).

We are grateful for Senator Shaheen's leadership in expanding opportunities for clean and efficient distributed generation and are hopeful that this provision will be incorporated into the Senate Committee on Energy and Natural Resource's forthcoming energy package. We believe that the Clean Energy Grid Integration Act will help make the U.S. electric grid more resilient, provide flexibility to U.S. electricity customers, and reduce emissions.

The member companies and organizations of the International District Energy Association (IDEA) own, operate, design and construct many forms of distributed generation including combined heat and power (CHP); biomass; geothermal; solar; waste energy recovery and storage serving customers in cities, communities and campuses. Many of our systems support mission-critical research on college and university campuses and healthcare settings.

Traditional central station power generating stations typically operate at fuel efficiencies of 32-34%, often wasting 2/3d's of the input energy in the form of waste heat. Central generation often involves higher up-front costs, much longer lead times and larger projects can be difficult to site. Clean and efficient, distributed generation sources can be deployed at a fraction of the cost, enabling the grid to be more resilient. This is particularly true in the case of energy sources that can function independent of the grid, providing enhanced reliability during extreme weather events, which may compromise central power plants. Distributed generation is also more efficient and avoids line losses associated with the transmission and distribution of centralized electricity. By investing in distributed generation, we can avoid costly upgrades to transmission and distribution infrastructure.

Consumers should have the freedom to choose the type of energy that powers their homes and businesses. Unfortunately, a variety of barriers, like complicated and burdensome interconnection procedures and exit fees, prevent distributed energy sources from reaching their potential. The Clean Energy Grid Integration Act will help to identify and overcome these barriers, so that the U.S. electricity system can be more diverse and resilient.

The Clean Energy Grid Integration Act reports on the status of grid integration and examines barriers that are limiting distributed generation sources from successfully connecting to the grid. It then establishes a stakeholder working group to determine the most appropriate way to overcome these barriers and

provides competitive grants to states to demonstrate best practices for successfully integrating clean, distributed energy sources into the electricity grid. This low-cost approach identifies a problem and provides incentives for states to determine the best way to overcome it. It does not place any mandates on states or utilities.

We look forward to helping this important legislation become law and in continuing to work with your office to explore – and overcome - barriers to deploying the clean, efficient and renewable technologies represented by our businesses and organizations.

Sincerely,

Robert P. Thornton

Robert P. Thornton
President & CEO
International District Energy Association
Westborough, MA USA

INGAA

DONALD F. SANTA
PRESIDENT & CEO

May 18, 2015

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
Washington, DC 20510

The Honorable Maria Cantwell
Ranking Member
Committee on Energy and Natural Resources
Washington, DC 20510

Dear Chairman Murkowski and Ranking Member Cantwell,

Thank you for conducting the May 14 hearing on energy infrastructure legislation. As part of the record for that hearing, I am submitting the comments of the Interstate Natural Gas Association of America, or INGAA. INGAA represents interstate natural gas transmission pipeline operators in the U.S. and Canada. Our 24 members operate the vast majority of the interstate natural gas transmission network, which is the natural gas industry analog to the interstate highway system.

The approval and permitting process for interstate natural gas pipelines has become increasingly challenging. While this remains a good, albeit complex, process, there have been some trends in the wrong direction. What was once orderly and predictable is now increasingly protracted and contentious.

Several bills have been introduced in the Senate to address the natural gas permitting process. For example, S. 1210, introduced by Senator Capito, would make some modest improvements in this process. While the pipeline certificate process at the Federal Energy Regulatory Commission generally functions in an orderly and timely fashion, interstate pipelines still must seek a multitude of permits from federal and state agencies before construction can begin. It is with these federal and state permits that many of the approval delays occur. S. 1210 introduces reforms aimed at bringing additional transparency and accountability to the permitting process for pipelines, and therefore has our support. INGAA continues to believe, however, that permitting agencies should face consequences for inaction or delay. We urge Congress to consider such consequences in future oversight and legislative efforts.

INGAA also supports two bills – S. 411 introduced by Senator Barrasso and S. 1196 introduced by Senator Cassidy – that would allow the Department of the Interior to review and approve natural gas pipeline rights of way on lands administered by the National Park Service without seeking a project-specific authorization from Congress. The Department of the Interior has had the authority to approve rights of way for electric, water and communications facilities on these lands, without prior authorization from Congress, since Theodore Roosevelt was president. The current process, which puts Congress in the role of a *de facto* permitting agency for an individual natural gas pipeline project, is peculiar and unnecessary. The Department of the Interior is perfectly capable of reviewing these proposals and making balanced decisions on its own. This is entirely consistent with the statutes authorizing other federal agencies, such as the Bureau of Land Management and the U.S. Forest Service, to issue permits for natural gas pipelines. Seeking a project-specific bill in Congress, which only allows the Department of the Interior to *negotiate* with a pipeline developer for a right of way and does not authorize the permit itself, adds years to the process. We hope Congress will act to delegate this permitting authority to the Department of the Interior.

Thank you for allowing INGAA to submit these comments for the record. Please let us know if you have any questions.

Respectfully,

Donald F. Santa

cc: The Honorable John A. Barrasso
The Honorable William Cassidy
The Honorable Shelley Moore Capito

THE LATINO COALITION
Celebrating 20 years

June 11, 2015

The Honorable Lisa Murkowski
Chairwoman
Energy and Natural Resources Committee
United States Senate
Washington, D.C. 20515

The Honorable Maria Cantwell
Ranking Member
Energy and Natural Resources Committee
United States Senate
Washington, D.C. 20510

Dear Chairwoman Murkowski and Ranking member Cantwell:

The Latino Coalition is one of the nation's foremost advocates for Latino-owned businesses and we serve as a vital voice in making sure Latino business owners thrive and contribute to our economy.

This is a critical time for America's entrepreneurs and those who hope to someday own their own business. The decline in business start-ups is casting a shadow over our country's economic potential and it has negatively impacted that American dream of owning and operating their own business and providing a legacy for their family.

Energy plays a key role in powering our economy and creating jobs for Latino families in the business sector, including starting their own business. Clean, reliable and affordable electricity is vital to the success of our economy and hardworking American in the United States. The Latino Coalition is asking for your support on the "Hydropower Improvement Act of 2015"

Hydro generation continues to be one of the best renewable energy sources of electricity in the country and it provides some of the lowest cost power to the small businesses we represent. However, the current regulatory process in place to relicense these facilities has become lengthy in years and very costly and unnecessarily duplicative.

While some in the environmental community see this as a way to fund their special interest projects, we view the existing policy as a way to keep energy cost high, and pass unnecessary cost onto small businesses and hard working families.

THE LATINO COALITION
Celebrating 20 years

The Latino Coalition is uniquely positioned to fight for the entrepreneurial climate that has made this nation a land of hope and upward mobility for generations of Latinos and affordable energy prices are an important part of making their family dream of owning and operating a business come true.

Thank you for your consideration.

Hector V. Barreto
Chairman

Allen Gutierrez
National Executive Director

National Headquarters: 1455 Pennsylvania Avenue NW ☆ Suite 400 ☆ Washington, D.C. 20004
Administrative Office: 8855 Research Drive ☆ Irvine, CA 92618
Office (Toll Free): 1 (855) 852-1995 ☆ Fax: (866) 496-1944
www.thelatinocoalition.com

THE PEW CHARITABLE TRUSTS

The Honorable Jeanne Shaheen
United States Senate
Washington, DC 20510

April 21, 2015

Dear Senator Shaheen,

Thank you for your stalwart leadership on energy and your policy efforts to ensure the broader deployment of clean and efficient technologies that deliver economic, national security and environmental benefits for America. We are pleased to support your forthcoming Heat Efficiency through Applied Technologies (HEAT) Act which breaks down regulatory barriers which prevent the more widespread adoption of combined heat and power and waste heat to power deployment.

These highly efficient technologies are critical to bringing down energy costs for adopters, ensuring greater reliability in times of grid outages and reducing pollution. We look forward to working with you and your staff on this bill.

Thank you,

Phyllis Cuttino
Director, Clean Energy Program
pcuttino@pewtrusts.org

PLASTICS·PIPE·INSTITUTE®

THE VOICE OF AN INDUSTRY

Energy Piping Systems Division (EPSD)

May 12, 2015

The Honorable Lisa Murkowski
Senate Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Chairman Murkowski,

The Plastics Pipe Institute (PPI) Energy Piping Systems Division (EPSD) promotes the use of plastic pressure pipe made of high-density polyethylene, polyamide, or composite piping included in gas distribution pipeline systems and oil and gas gathering applications. PPI/EPSD appreciates your leadership in developing a comprehensive energy bill in first session of the 113th Congress, and we encourage the inclusion of legislation that would streamline the sluggish process of issuing federal rights-of-way for gas gathering systems on public lands and approving permits for natural gas pipelines.

Flaring of natural gas occurs when it is burned on location due to a lack of gathering pipeline infrastructure or economic alternatives. In oil-rich areas such as the Bakken Shale some 30 percent of natural gas is flared off due to numerous logistical, political and regulatory challenges. This makes for a grim scenario as huge amounts of potential income, profit and tax revenue are lost while tons of carbon based emissions are released into the atmosphere unnecessarily.

Federal issuance of ROWs for gathering systems can take up to several years. Meanwhile, according to a 2014 report by the Interstate Natural Gas Association of America (INGAA) Foundation, almost 14,000 miles of new gas gathering pipelines will be needed annually, requiring significant investments that create tens of thousands of jobs and generates considerable economic activity. PPI/EPSD estimates that 25 million feet of spoolable composite pipe used increasingly in gas and oil gathering systems is produced and distributed every year, further contributing to the economic benefit of the American energy revolution.

Introduced by Sen. John Barrasso, the Natural Gas Gathering Enhancement Act (S 411) would mitigate the problem with unnecessary flaring by requiring the Department of Interior to issue a ROW for gas gathering pipelines on federal and tribal lands within 90 days of receipt unless it would violate existing federal law. PPI/EPSD strongly supports this important legislation.

PPI/EPSD also supports legislation (S 1210) that would help streamline the process of approving natural gas pipeline permit applications by requiring cooperation from every federal and state agency involved in the process. The bill calls for firm deadlines to approve or deny permits and concurrent reviews by state and federal agencies in conjunction with National Environmental Policy Act (NEPA) reviews.

Improving our antiquated pipeline permitting process is a priority for PPI/EPSD, and we applaud your hard work to improve American energy policy in this Congress.

Best Regards,

Randall Knapp, Director of Engineering

105 Decker Court • Suite 825 • Irving, Texas 75062 • 469.499.1044 • www.plasticpipe.org

Testimony of Senator Jeanne Shaheen
Before the Committee on Energy and Natural Resources
Hearing on Energy Infrastructure Legislation
May 14, 2015

Chairman Murkowski, Ranking Member Cantwell and Members of the Committee:

Thank you for the opportunity to submit testimony today before the Energy and Natural Resources Committee in the area of energy infrastructure.

Today, America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s. Therefore, substantial investments and policy changes are urgently needed to improve our transmission and distribution infrastructure. I commend Chairman Murkowski and Ranking Member Cantwell for including an infrastructure title in the comprehensive energy bill.

I am pleased that the Committee has decided to focus on two of my bills during today's hearing: the Clean Distributed Energy Grid Integration Act and the Heat through Applied Technology (HEAT) Act. Both pieces of legislation ensure the broader deployment of clean and efficient technologies and will strengthen our nation's energy security, reduce pollution, increase electric reliability and spur job creation in the clean energy industry.

The Clean Distributed Energy Grid Integration Act establishes initiatives to identify and overcome technical and regulatory barriers to the wider use of cleaner and more efficient energy technologies. Often the cheapest and most reliable energy sources, clean distributed energy, such as solar, fuel cells, combined heat and power (CHP), waste heat to power (WHP) and energy storage, generate onsite electricity with little or no pollution or harmful emissions.

The benefits of clean energy are countless and include energy savings, improved environmental quality, avoidance of costly upgrades to transmission and distribution infrastructure, and grid reliability in the event of electricity outages or emergencies. Clean energy technologies, however, have been hampered by regulatory and technical challenges that limit their deployment and integration into the electricity framework.

The Clean Distributed Energy Grid Integration Act directs the Secretary of Energy to develop efforts focused on advancing the integration of clean distributed energy into electric grids. It does so by convening a stakeholder working group, engaging in research to address technical and regulatory barriers, and providing support for demonstrations of intelligent integration systems for distributed generation that are dynamic in response to changing grid conditions. Policies set forth in this legislation will help bring clean energy resources online, while optimizing the quality and reliability of a smarter and more reliable electric grid.

My second bill, the HEAT Act, will also encourage the deployment of CHP and WHP, both of which would strengthen local economies and support national energy goals. The bill addresses regulatory barriers impeding CHP and WHP by providing assistance to states in adopting updated interconnection procedures and tariff schedules, establishing standards for supplemental, backup, and standby power fees for CHP and WHP systems, and implementing the most recent EPA guidance on output-based emission standards. It does this without imposing any new mandates.

In recent months, my staff and I have met with a number of trade associations, companies and organizations who have interest in the development, implementation, siting and integration of clean distributed energy sources into the electric grid. These groups represent different sectors of the economy and have different interests, but all agree that encouraging the deployment of clean distributed energy will spur economic growth, reduce business risk from energy price volatility and create jobs. I am proud to say that the Clean Distributed Energy Grid Integration Act and the HEAT Act have received broad support among the energy community.

Passage of these two complimentary bills would be important steps towards improving America's energy infrastructure. For this reason, I respectfully request that the Senate Energy and Natural Resources Committee consider both for inclusion in the infrastructure title of the Committee's comprehensive energy bill.

The Clean Distributed Energy Grid Integration Act (S.1201)

The Clean Distributed Energy Grid Integration Act will strengthen our nation's energy security, reduce pollution, increase electric reliability and spur job creation by improving the deployment of efficient and cost effective energy resources like solar, wind, energy storage, combined heat and power (CHP), fuel cells and waste heat to power (WHP).

Often the cheapest, most reliable and efficient energy source, distributed energy creates electricity at or near the customer, as opposed to centralized generation at large power plants that often requires electricity to be transmitted long distances to consumers. While large power stations are costly to build and often difficult to site in densely populated areas, distributed energy can be rolled out quickly at a fraction of the cost, providing targeted, localized relief to the grid. The benefits of clean energy are numerous and include energy savings, improved environmental quality, avoided costly upgrades to transmission and distribution infrastructure and grid reliability in the event of electricity outages or emergencies.

Despite the economic, energy and environmental benefits of clean distributed energy sources, complicated regulatory and technical challenges limit its deployment and integration onto the existing grid. For example, the absence of uniform procedures, coupled with excessive fees to connect these efficient and more affordable energy systems to the electric grid, often prevents their more widespread use.

With the installation of clean energy resources becoming more prevalent, regulators, utilities and leaders in this sector need to determine how distributed energy systems will work together for the benefit of the grid. The Clean Distributed Energy Grid Integration Act addresses obstacles limiting the use of clean distributed energy resources, thereby reducing energy costs and improving the power quality and resiliency of the electric grid.

What the Clean Distributed Energy Grid Integration Act Will Do

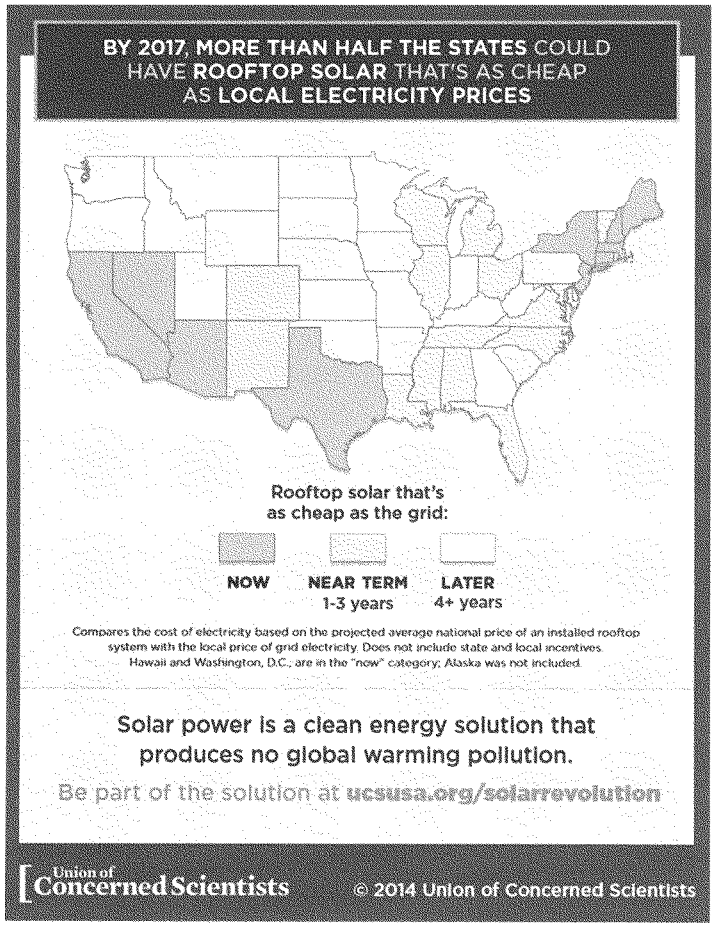
- **Reports on the Status of Grid Integration**
  - Directs the Department of Energy (DOE) to develop a report that will detail the status of integration of distributed energy technologies into the grid and identify all technical and regulatory hurdles that inhibit the expanded usage of clean energy resources.
- **Researches Technical Barriers Limiting the Grid Integration of Clean Distributed Energy**
  - Directs the DOE to solicit research proposals that will address critical technical barriers impeding distributed energy grid integration.
- **Creates a Stakeholder Working Group to Provide Solutions to Clean Energy Challenges**
  - Directs the DOE to convene a Stakeholder Working Group consisting of representatives with expertise in the development, implementation, siting and integration of distributed energy technology or systems into the electric grid.
  - The Stakeholder Working Group will be charged to review regulatory policies and provide solutions to obstacles limiting clean energy integration.
- **Demonstrates Intelligent Grid Integration of Clean Distributed Energy Systems**
  - Creates a competitive grant program for entities to demonstrate how to achieve successful integration of distributed energy sources into the electricity grid.
  - This grant program is open to State and local agencies, public and private institutions, electric utilities and equipment manufacturers.

Union of Concerned Scientists
Science for a healthy planet and safer world

Congress Can Empower Energy Innovation Far and Wide. Here's How.

Mike Jacobs, senior energy analyst, Climate & Energy Program
May 14, 2015

Today there is much attention to new energy supplies, and the policies that can best guide their adoption. As part of that discussion, it's important to note that most of the new technology and market-based behavior by users and suppliers of electricity stems from Congress passing the Public Utility Regulatory Policies Act (PURPA) and its amendments.

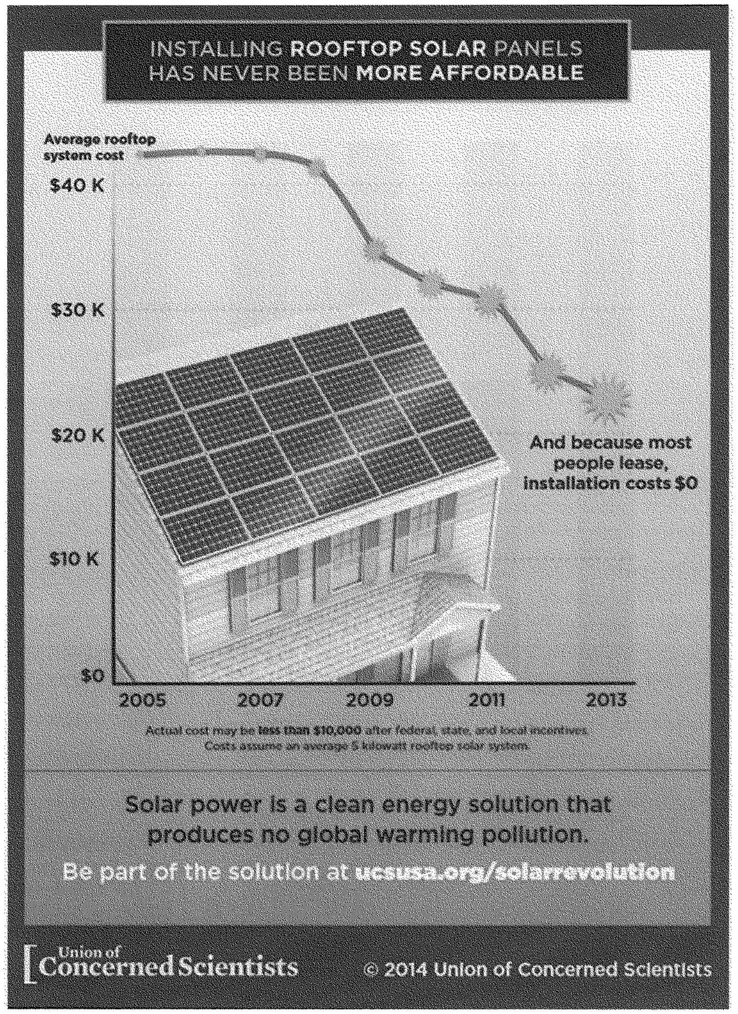


Congress poised for resilience and grid reforms

Senator Lisa Murkowski (R-Alaska) is guiding hearings on energy delivery. The range of bills from both parties in Congress illustrates that energy topics reach far and wide. Keeping the lights on in isolated communities with micro-grids helps advance the resilience of any community that seeks to build micro-grids. Providing the tools and demonstrations for making the grid run with renewable energy and storage allow for better service, even if storms disrupt the delivery of fuel.

The Center for American Progress (CAP) has made a great contribution to Congressional energy bill efforts. CAP points to how Congress has helped advance energy policy adaptations to changes in the economy, and national needs for reform in the energy sector. Congress has used legislation under PURPA and its amendments over the years to start discussions and still provide that states maintain the jurisdiction to decide on the policies.

PURPA allowed literally a new generation of power plant entrepreneurship by introducing competition from new power supplies. This included small, customer-owned generation, which has blossomed with rooftop solar. Projections of how much solar is likely are hard to make, as actual installations have surpassed most every prediction. Business innovation allows solar on rooftops with no money down, demonstrating that solar is for everyone, and entrepreneurship in clean energy can be as aggressive and clever as in any other field. Enter "solar no money down" in an internet search and see for yourself!



"The Public Utility Regulatory Policies Act has repeatedly proven itself as a modest but useful tool for Congress to encourage smart standards for utilities at the state level," explains CAP. PURPA has encouraged states to examine rates and energy supply decision-making in response to rising costs. Congress has used PURPA to promote better understanding of energy use and supply diversity, topics ripe for today's needs. CAP today urges Congress to continue this work by using PURPA to advance:

- Energy-efficiency incentives and affordability;
- Integrating clean energy and energy storage into the grid; and
- Increasing resilience of utilities.

Falling costs and grid adaptation

With the quickly falling costs of renewable energy, and the promise of low-cost storage, even greater changes are looming in the marketplace.

The bill from Maria Cantwell (D-Washington) urges storage industry transparency and standards that can speed adoption and customer confidence. As many of the bills proposed in Congress suggest, we can learn how to adapt to the technological and business changes through science, demonstration, and deliberation of the merits.

The electric utility industry has said it wants to provide an "integrated grid." Debating how to pay for the grid needs time and thought, as energy use changes with distributed generation reducing utility sales, and electric vehicles increasing utility sales. The utility industry needs to give a clear signal that it has the capability to measure the true costs and benefits of these changes.

The time is ripe for Congress to provide an updated policy platform for the energy business. Congress has the opportunity to encourage modernization of the power system. Competition, customer choice, and new technology have been the legacy of past Congressional guidance on electricity policy. The business community is ready to offer a new generation of technology. Let's keep working on this in a balanced manner.

Posted in: Energy Tags: clean energy, Renewable energy, solar power

About the author: Michael Jacobs is a senior energy analyst with expertise in electricity markets, transmission and renewables integration work. See Mike's full bio.

[Union of Concerned Scientists

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May 14, 2015

The Honorable Lisa Murkowski
Chairman
Senate Energy and Natural Resources Committee
709 Hart Senate Office Building
Washington, D.C. 20510

The Honorable Maria Cantwell
Ranking Member
Senate Energy and Natural Resources Committee
511 Hart Senate Office Building
Washington, D.C. 20510

Dear Chairman Murkowski and Ranking Member Cantwell:

On behalf of the Union of Concerned Scientists, and our almost 500,000 members and supporters, I am writing to thank the Committee for recognizing the critical need to improve and modernize our nation's energy infrastructure. The way we are producing electricity is changing, and Congress must lead in removing barriers to progress. If our electric grid is to reflect 21st century thinking, we must abandon the notion that conventional base load electricity is a superior structure to distributed generation. Likewise, we must also challenge paradigms about reliability and scalable clean energy technologies, and use the existing electricity infrastructure to deploy more renewable energy. We applaud the committee for thoughtfully deliberating policies that modernize our energy infrastructure and help speed the necessary transition to a clean energy economy, in the spirit of bipartisanship.

Please note our strong support for the following proposed legislation:

S.1017—Improve Interstate Electric Transmission Facilities
This bill, introduced by Senator Heinrich, encourages the expansion of high-priority regional transmission projects by amending the Federal Power Act to allow the Federal Energy Regulatory Commission to authorize construction of the projects found to be required by public convenience and necessity in certain circumstances. It is critical to the support of this policy that high-priority regional transmission projects are required to be clean and efficient and do not contribute to climate change. This bill provides a valuable tool for bringing more clean energy onto the grid through expanded federal authority for transmission siting.

S.1201—Clean Energy Grid Integration Act
This bill, introduced by Senator Shaheen, requires a study on the technical and regulatory barriers to the integration of clean distributed energy with the grid. The bill also creates a stakeholder working group and a merit-based grant program to award demonstration projects that overcome reported technical barriers. This policy will help us identify the challenges we need to address in order to develop a cleaner, more efficient system of electricity distribution.

S. 1202—HEAT Act
This bill, introduced by Senator Shaheen, encourages the expansion of combined heat and power distributed energy generation by adopting updated standards to address interconnection procedures, tariff schedules, and standards for combined heat and power technology and waste heat to power technology. The bill creates policy based on several scientific reports that have identified barriers and benefits in combined heat and power technologies.

S.1207—Next Generation Electric Systems Act
This bill, introduced by Senator Hirono, establishes a grant program for projects that will improve the performance and efficiency of the future electric grid to partnerships between institutes of higher education, national laboratories, state, local or tribe governments, nonprofit industry trade associations, the federal power marketing administration, an industry expert and a utility, systems operatory, technology provider, and regional transmission organizations. UCS supports the grant program's focus on funding projects that will provide innovation in the near future and will be commercially available, scalable and replicable.

S. 1213—Free Market Energy Act
This bill, introduced by Senator King, creates guidelines and improves rate assessment techniques to remove existing barriers to the market for distributed energy resources. UCS supports the policies in this bill as a tool to ensure these decisions accurately and comprehensively consider opportunities to expand distributed energy resource technologies.

S. 1217—Electric Transmission Infrastructure Permitting Improvement Act
This bill, introduced by Senator Murkowski, recognizes the need to increase interagency coordination, documentation, transparency, and accountability in the federal permitting process for transmission projects. This is critically important to increasing the amount of clean energy in our national electricity mix.

S. 1220—Energy Distribution Act
This bill, introduced by Senator Murkowski, requires the Department of Energy to enact recommendations from the Quadrennial Energy review, including improving data collaboration. UCS supports policies that result in improved collection of reliable data and collaboration.

S.1227—Micro-Grid Implementation Strategy

This bill, introduced by Senator Murkowski, promotes the expansion of micro-grid technologies for renewable resources by requiring the Department of Energy to develop an implementation strategy for these micro-grids in isolated communities. This program will help these isolated communities by providing a more reliable, clean power supply and provide replicable demonstration projects to encourage renewable micro-grid deployment nationwide.

S.1232—Smart Grid Act
This bill, introduced by Senator Wyden, provides strong support to improve smart grid modernization by providing grants for smart grid demonstration projects. It rejuvenates the Smart Grid Interoperability Working Group and extends federal matching funds for smart grid investment costs. A more efficient grid reduces harmful fossil fuel emissions and has economic benefits for consumers.

S.1233—PURPA Plus Act
This bill, introduced by Senator Wyden, encourages the expansion of distributed generation technologies by amending the Public Utility Regulatory Policies Act to provide states with regulatory flexibility and authority to incentivize qualifying cogeneration and small power production facilities. It also removes avoided cost caps on qualifying facilities of not more than 2 megawatts capacity, which allows states to set the rates for these qualifying facilities. The freedom provided to states from these amendments may provide more flexibility to address existing market barriers to distributed energy generation technologies integration into the utility grid.

S.1243—Grid Modernization Act
This bill, introduced by Senator Cantwell, makes great strides towards promoting the modernization of the electric utility grid, the integration of distributed generation technologies, and the resiliency of the grid against hazards including extreme weather events. There are several outstanding programs established in this bill, including the grid storage program, resilient communities program, voluntary model pathways program, technology demonstration on the distribution program, and the program to develop and model grid architectures in future scenarios.

Sincerely,

Robert Cowin
Director of Government Affairs, Climate and Energy Program
Union of Concerned Scientists

Union of Concerned Scientists

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May 14, 2015

The Honorable Lisa Murkowski
Chairman
Senate Energy and Natural Resources Committee
709 Hart Senate Office Building
Washington, D.C. 20510

The Honorable Maria Cantwell
Ranking Member
Senate Energy and Natural Resources Committee
511 Hart Senate Office Building
Washington, D.C. 20510

Dear Chairman Murkowski and Ranking Member Cantwell:

The Union of Concerned Scientists is writing to offer support for S. 1213, *The Free Market Energy Act of 2015*. This bill offers an innovative solution to modernize the nation's electricity grid and deploy distributed energy resources on a large scale. Utility scale deployment of distributed energy resources will be vital as the nation increasingly integrates clean, renewable fuel as sources for electricity generation. Incorporating distributed energy resources on a large utility scale is necessary to transition the nation's power sector away from dirty fossil fuels and limit the harmful impacts from climate change.

Distributed energy resources (DER) include several facets of the clean power technology revolution which Americans are familiar with, e.g. solar panels on a roof, battery storage, and energy efficiency measures. DER technologies exist now and have largely proven successful when deployed. However, outdated government policies and inaccurate formulas used in net energy metering studies create barriers to the market that are stifling the expansion of these technologies.

The *Free Market Energy Act of 2015* makes progress towards breaking down these market barriers and creating a free market ripe for DER technology expansion in several ways. First, the bill finds that it is in the public interest to reinforce the right to sovereignty over personal energy choices with a comprehensively defined use of DER. Second, the bill provides a general right that DER are allowed to interconnect to the existing grid in a reasonable timeframe.

Third, the bill recognizes the importance of establishing fair rates in DER deployment. The bill addresses the issue from several angles. The bill specifies that any fees charged for interconnection are just, reasonable, do not exceed the actual cost of service, and account for both the benefit of DER to the grid and the grid to DER. The bill then stresses the importance of improving the current net energy metering studies. To ensure the rates set do not create an unfair disincentive to the marketplace it is critical that rates are established by considering DER in an unbundled manner with net energy metering.

The bill also notably requires states to consider alternatives to transmission when considering transmission upgrade proposals and requires states to consider the designation of a smart grid coordinator to manage DER. UCS is supportive of both these policies. The consideration of alternatives to transmission during the project proposal process will create an opportunity to consider DER and other non-transmission alternatives which may save ratepayers money over implementing the traditional options. The designation of a specific office to manage DER in each state can be useful in increasing DER projects from creation to integration.

Decisions made today about where and how to invest in the utility sector and nation's electricity grid will have impacts on public health, security, and resiliency for the next several decades. This bill supports the integration of the innovative and available clean energy technologies into the grid infrastructure by providing a set of guidelines that removes existing market barriers, improves the accuracy net energy metering rates. UCS supports the policies in *S. 1213* as a tool to ensure these decisions accurately and comprehensively consider opportunities to expand distributed energy resource technologies.

Sincerely,

Robert Cowin
Director of Government Affairs, Climate and Energy Program
Union of Concerned Scientists

WESTERN ENERGY
ALLIANCE

May 18, 2015

The Honorable John Barrasso
United States Senate
307 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Senator Barrasso:

Thank you for introducing S. 411, the *Natural Gas Gathering Enhancement Act*, which expedites the permitting of Rights of Way (ROW) for certain natural gas gathering lines on federal and Indian lands. The act is a common-sense way to reduce the incidence of flaring and venting from oil wells within the jurisdiction of the federal government as well as on private lands that require a ROW through federal lands.

The rate of flaring and venting is often higher on federal and tribal lands because of inefficient permitting by the Bureau of Land Management (BLM) and the Bureau of Indian Affairs. By requiring more judicious processing, the federal government could become part of the solution to increasing rates of gas capture from oil wells, rather than being a stumbling block as is currently the case.

In fact, BLM has embarked on a rulemaking process to reduce flaring and venting, yet the simple act of processing ROWs in a timely manner, as your bill mandates, would be a more straightforward and efficient way to achieve that goal. As BLM struggles to meet its current oil and natural gas obligations, the simple changes required in your bill could save BLM a long and costly rulemaking. This is especially important in today's current environment when BLM is struggling to implement a new hydraulic fracturing regulatory regime, update several onshore orders, finalize 68 land use plans with sage grouse amendments, institute new planning processes, and implement many other new requirements that the Administration has imposed on it. Your bill accomplishes the goal of BLM's current rulemaking with higher efficiency and lower cost.

We appreciate your leadership on this issue and support of responsible oil and natural gas development in the West. Western Energy Alliance stands ready to support you in advancing this legislation to increase the rates of natural gas capture.

Sincerely,

Kathleen M. Sgamma
Vice President of Government & Public Affairs

1775 Sherman St., Ste 2700 Denver, CO 80203
P 303.623.0987 F 303.893.0709 W WesternEnergyAlliance.org

THE WILDERNESS SOCIETY

Wednesday, May 13, 2015

Chairman Lisa Murkowski
Senate Energy & Natural
Resources Committee
304 Dirksen Senate Building
Washington, D.C. 20510

Ranking Member Maria Cantwell
Senate Energy & Natural
Resources Committee
304 Dirksen Senate Building
Washington, D.C. 20510

Dear Chairman Murkowski & Ranking Member Cantwell,

The Wilderness Society respectfully requests that this letter expressing our views on various bills before your committee be included in the Senate Energy and Natural Resources Committee hearing record regarding "Energy Infrastructure Legislation." We commend the Committee's efforts to engage in a series of hearings to consider legislation in a bipartisan manner, and thank you for your leadership in beginning work on a comprehensive energy package.

As you know, our nation's public lands are looked to for many things including economic opportunities, world-class hunting and angling, and resources for energy development. We at The Wilderness Society know from decades of experience that smart policies based on forward looking planning, with adequate input from all stakeholders, can provide our nation with the resources we need while also protecting the places that we love.

As you consider legislative proposals for America's energy future, we encourage you to keep in mind the many benefits that come from conserving our public lands - both through renewable technology and land conservation - and accept our initial views on promising ideas in the following bills:

S. 1213, the Free Market Energy Act of 2015. This bill would amend the Public Utility Regulatory Policies Act of 1978 and the Federal Power Act to define a number of renewable energy sources, including solar, wind, fuel cells, and combined heat and power, as distributed energy and directs standards to ensure that such sources are able to connect to the grid in a reasonable time frame and with reasonable user fees.

S 1217, the Electric Transmission Infrastructure Permitting Improvement Act. This bill establishes an Interagency Rapid Response Team for Transmission to expedite the permitting process for electric transmission infrastructure on federal and non-federal land. It also builds on a 2009 Memorandum of Understanding between the Federal Energy Regulatory Commission (FERC), the U.S. Department of Energy , U.S. Department of the Interior, U.S. Department of Defense, U.S. Department of Agriculture, Council on Environmental Quality, U.S. Department of Commerce, Advisory Council on Historic Preservation and U.S. Environmental Protection Agency to coordinate their efforts on transmission. Lastly, this bill creates an ombudsperson at FERC to resolve interagency delays or issues on transmission permits.

S. 1243, the Grid Modernization Act of 2015. This bill authorizes $200 million each year for non-cyber security activities at the Office of Electricity Delivery and Energy Reliability to modernize the grid. The bill authorizes research and demonstrations programs to improve grid storage, distribution, and resiliency. It also provides tools for states regulators and regional planners for planning, analysis, and implementation of new pathways.

S. 1232, the Smart Grid Act of 2015. This bill would amend the Energy Independence and Security Act of 2007 to modify provisions to require the Department of Energy to develop data sharing standards and utility-consumer communications to improve reliability of the grid. It would also provide for smart grid demonstration projects to further the goal of a fully operational smart grid and reauthorize section 1306 of the Energy Independence and Security Act of 2007, which offers matching federal funds to smart grid investments made by business, homeowners, vendors, and utilities.

S. 1207, the Next Generation Electric Systems Act. This bill would authorize and direct the Secretary of Energy to establish a grant program under which the Secretary shall make grants to eligible partnerships to provide for the transformation of the electric grid by the year 2030 through investments in grid technology and infrastructure.

America's public lands are a vital aspect of our American heritage and the prevailing spirit of our nation. As we work to develop reliable and affordable energy, it is necessary that that we give due credence to the landscapes that support various economies and inspire our culture. With this in mind, we would like to flag our initial concerns with the following bills:

S 1196, the Federal Land Access Act. This bill would amend the Mineral Leasing Act to provide the Secretary of the Interior with the authority to approve natural gas pipelines through national parks, which currently can't be authorized without explicit approval from Congress. The current protection for our national parks is a critical piece of our American heritage and should be preserved. The 1973 amendments to the Mineral Leasing Act must be maintained to uphold the integrity and values of the National Park System.

S 411, the Natural Gas Gathering Enhancement Act. This bill would authorize the approval of natural gas pipelines and fast-track for permits for natural gas gathering lines in National Parks in California, on Indian land and other valuable public lands. It sets a 90-day deadline for the Interior Department to approve rights-of-ways (ROWs) for natural gas gathering lines and compressors on public lands unless they would violate the National Historic Preservation Act or Endangered Species Act and creates a categorical exemption from the NEPA for certain gathering gas lines and associated compression units. It could indirectly incentivize more oil and gas development on federal land due to the increase in infrastructure near important publicly owned lands.

S 1210, the Oil and Gas Production and Distribution Reform Act of 2015. This bill would allow the Federal Energy Regulatory Commission (FERC) to require a 90-day deadline for approval from any state or federal government agencies involved in the permitting process. During this time, those agencies must fulfill any NEPA requirements. It also could take decision authority away from land managers who know best what's appropriate for the public lands in question when resolving any issues that may delay or deny environmental permitting.

S 1225, the Federal Land Assessment Inventory Reform Act of 2015. This bill would require the Secretary of Interior to develop a multipurpose cadastral survey of Federal real property and identifying inaccurate, duplicate, and out-of-date Federal land inventories to facilitate proposals to sell off America's public lands. While we're not opposed to data transparency, we hope that testimony by the Department of the Interior's U.S. Geological Survey on a similar proposal in 2013 will be weighed before moving forward. In this testimony USGS stated that the project, "would provide little new critical information about the lands the Federal government manages" and that "a very rough estimate suggests that the cost could run in the many billions of dollars." Furthermore, we're concerned that this bill would encourage the sell-off of public lands, which is in direct contrast with consistent public polling showing that Westerners from all political parties strongly oppose proposals to sell off America's public lands.

Thank you for the opportunity to provide our views. We look forward to working with you as this process continues to move forward. As you work on national energy policy, we hope you will contact us for strategies that align our energy development needs with conservation and protection of our public lands.

Sincerely,

The Wilderness Society

WIRES

POST-HEARING WRITTEN TESTIMONY OF WIRES, LLC
ON
ENERGY INFRASTRUCTURE LEGISLATION

Before the Committee on Energy and Natural Resources
United States Senate

Chair Murkowski, Ranking Member Cantwell, and Members of the Committee:

WIRES[1] respectfully submits the following comments on certain of the bills considered during the **hearing of May 14, 2015**, and on the oral testimony provided to the Committee. WIRES thanks the Chair for affording the industry an opportunity to enhance and complete the record of this proceeding. WIRES applauds the Committee for preparing to move energy legislation forward for the first time in several Congresses.

WIRES contends that the Committee's consideration of improvements to energy infrastructure must include the future of investment in the high-voltage electric transmission network. Past experience shows that inadequate investment in the grid brings with it enormous reliability risks and costs, hampers markets and competition, and limits resource diversity. A new analysis recently conducted for WIRES confirms that, notwithstanding the major transmission investment in recent years, the potential high risks and costs to future consumers and the economy that will result from poor transmission planning practices and insufficiently robust investment in the most beneficial projects are not diminishing.

WIRES believes that many of the Committee's proposed legislative reforms are constructive and could help ensure that transmission facilities are evaluated more expeditiously, despite the cumbersome nature of the current regulatory regime that governs transmission.[2] The Energy Policy Act of 2005 exhibited a clear policy of encouraging transmission development through incentives, federal backstop siting, encouragement of regional interstate compacts, and coordination of federal agency

[1] WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned and environmentally beneficial high-voltage electric transmission network. WIRES wishes to foster an understanding among policy makers and the public of the evolving role of the transmission grid in the 21st Century electrical economy. Its principles and other information are available on its website: www.wiresgroup.com.

[2] Hoecker & Smith, *Regulatory Federalism and Development of Electric Transmission: A Brewing Storm?*, 35 Energy Law L.J. 71 (2014).

authorizations. However, those measures have not produced the anticipated results. Rather than argue for more comprehensive reforms at this time, WIRES simply urges the Committee to continue its ongoing oversight efforts to promote infrastructure investment by reducing federal regulatory burdens and holding the Federal Energy Regulatory Commission ("FERC") to a standard of performance that will lead to construction of regional and interregional transmission projects that are capable of delivering multiple benefits to the system and the economy. The tools and analytical techniques that will ensure that transmission planners support the most beneficial projects are readily available but are not used. After four years of implementation and debate, FERC's Order No. 1000 fails to require the use of new techniques and approaches, such as scenario planning and consideration of all potential project benefits that could ensure the development of the most beneficial transmission projects. The fact that interregional project development (*i.e.*, development between two or more regional transmission organizations or bilateral markets) is languishing altogether should be of concern to the Committee, and should be addressed along with the historical complications surrounding transmission permitting and siting that remain serious impediments to infrastructure development.

THE IMPORTANCE OF THE INTEGRATED TRANSMISSION NETWORK TO IMPLEMENTATION OF THE COMMITTEE'S PROPOSALS

The Committee's legislative proposals in the area of distributed generation, energy efficiency, micro-grids, storage, and other innovative technologies are a recognition that the industry's current structure and operation will change in fundamental ways in the coming decades. However, WIRES' own research and reports demonstrate that these innovations will be deployed and will succeed in proportion to the ability of the grid to support, aggregate, deliver, and deploy them. Grid "modernization" does not pose an 'either-or' choice between transmission investment and distributed technologies as much as it forces us to recognize that, as our electric system evolves, it will require a resilient, adaptable platform to support innovation. That platform is high-voltage transmission in interstate commerce, which in most cases will span multiple jurisdictions, resource bases, and regulatory preferences and protocols.

Transmission, if adequate, will be instrumental in making this transformation economically efficient and reliable. The recent testimony before this Committee by American Electric Power executive Lisa Barton[3] sets forth three fundamental propositions that make investment in a strong electric transmission system a winning proposition for technological innovation:

She stated, and WIRES concurs, that:

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[3] *State of Technological Innovation Related to the Electric Grid:* before Senate Energy and Natural Resources Committee, 114th Cong. (March 17, 2015) (Statement Lisa M. Barton, Executive Vice President, Transmission, American Electric Power).

- A robust grid is a critical enabler of generation diversity, new storage and demand-side technologies.
- Maintaining a reliable and resilient grid is critical to economic and national security.
- To maximize the beneficial impact of new technologies, policymakers should avoid picking winners and losers and allow the market to identify the best solutions for a particular circumstance.

Remarkably, new levels of U.S. transmission investment (averaging over $10 billion annually over several years to date) and the persistent folklore about the possibility that transmission could be "overbuilt" have obscured both an understanding of the long-term need for investment in this infrastructure and the fact that planners regularly overlook or reject transmission projects that could yield the most economic, reliability, and public policy benefits, because utilization of modern benefit/cost analysis is difficult and the exception in planning practices, especially when proposed projects are interregional. The industry's ongoing transformation, including foreseeable changes in the electric generation mix, creates significant uncertainties. For that reason, policy makers are increasingly open to a basic reassessment of how long-term planning of the grid is performed.[4] Therefore, in response to the portrayals of transmission expansion as an opponent of new technologies and services or a competitor to existing electric generation, WIRES requested London Economics International ("LEI") to explore the relationship between demand-side resources, storage, micro-grids, and other so-called "market resource alternatives" ("MRAs")[5] and investment in high-voltage transmission.

The completed study concluded that "based on the characteristics of MRAs today, MRAs are rarely a complete substitute to transmission, and individual MRAs typically provide only a partial suite of the services that transmission provides. Nevertheless, MRAs (either individually or in combination) can provide specific benefits and can serve as complements to transmission, and vice versa."[6] The LEI study is the state-of-the-art analysis of how mutually dependent investment in

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[4] For example, the Indiana Utility Regulatory Commission staff recently noted that:

> [F]ew industries are as important as the electric system, which has been called the most complex man-made system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The urgency for continual and immediate improvements are heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and new technologies.

See Draft Report of The Indiana Utility Regulatory Commission, Electricity Director Dr. Bradley K. Borum, Regarding 2014 Integrated Resources Plans (March 3, 2015) at 2.

[5] Although Order No. 1000 describes these technologies as "non-transmission alternatives", the LEI authors re-designated NTAs as "Market Resource Alternatives" ("MRAs") in the resulting study because these technologies are so seldom viable substitutes for transmission in the planning and operation of the utility functions.

[6] Julia Frayer & Eva Wang, *A WIRES Report:, Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, 136-142 (London Economics International LLC 2014) Appendix A is a comparison of services provided by MRAs and transmission. It is taken from the London Economics study, at Figure 2. The report is available at http://www.wiresgroup.com/wires_reports.html.

transmission infrastructure and investment in new market technologies have become. In sum, WIRES contends that this fundamental compatibility of new technology and the grid can help chart a new direction for legislation and for transmission planners who will be responsible for creating a future "network of things" in the electricity area, just as a platform of network facilities have fostered innovation on the Internet and across the interstate highway system. The efficiency goals of many of the bills being considered by the Committee are compatible with, and in many cases dependent upon, a robust transmission system. There is no basis for excluding measures favoring pro-transmission investment from consideration in omnibus electricity legislation.

THE IMPORTANCE OF CONTINUED TRANSMISSION INVESTMENT

The U.S. Department of Energy's National Electric Transmission Congestion Study[7] highlighted the problems that result from a common failure of planners to examine and consider all of the transmission benefits that a transmission project can produce:

> Construction of major new transmission facilities...raises unique issues because transmission facilities have long lives—typically 40 years or more. Evaluating the merits of a proposed new facility is challenging, because common practices take into account only those expected costs and benefits from a project that can be quantified with a high degree of perceived certainty. This has two effects:
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> First, it leads to a focus on the subset of cost and benefits that can be readily quantified. Not taking into account the costs and benefits that are hard to quantify has the effect of setting their value to zero in a comparison of costs and benefits.
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> Second, it leads to projections of costs and benefits that are generally based on extrapolations drawn from recent experiences. Projections based only on recent experiences will not value the costs and benefits a transmission project will have under very different assumptions or scenarios regarding the future because they ignore or discount the likelihood of these possibilities. Such a narrow view of the range of costs and benefits that could occur provides a false sense of precision.
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> [O]ne of the most strategically significant aspects of major transmission projects that is seldom taken into account explicitly in the planning phase is the multiple purposes that transmission might serve. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. . . . The options

[7] U.S. Dept. of Energy, *National Electric Transmission Congestion Study* (August 2014) at xiii-ix.

created by a strong and flexible transmission network are real. Failure to take explicit account of these options in the planning process will severely understate the value of transmission.

The key deficiencies in the way that U.S. transmission planners plan for the expansion and upgrade of the system have recently been identified and explored in a study by The Brattle Group ("Brattle"). These deficiencies, asserts the study, will result in ineffective and insufficient grid infrastructure, with fateful consequences:

- Planners and policy makers do not account for the high costs and risks of an insufficiently robust and insufficiently flexible transmission infrastructure on electricity consumers and the risk-mitigation value of transmission investments to reduce costs under potential future stresses.
- Planners and policy makers do not consider the full range of benefits that transmission investments can provide and thus understate the expected value of such projects.
- The interregional planning processes are ineffective and are generally unable to identify valuable transmission investments that would benefit two or more regions.

These deficiencies collectively create significant barriers to developing the most valuable and cost effective regional and interregional transmission projects and infrastructure. If not addressed, these deficiencies will lead to: (a) underinvestment in transmission that results in higher overall costs; (b) lost opportunities to identify and select alternative infrastructure solutions that are lower-cost or higher-value in the long term than the projects proposed by planners; and (c) an insufficiently robust and flexible grid that exposes customers and other market participants to higher costs and higher risk of price spikes. . . .

In an industry where it can take a decade to plan, permit, and build major new transmission infrastructure, ***further delaying investment by understating transmission-related benefits can easily result in a higher-cost, higher risk outcome that is exactly the opposite of the goals of "conservative" planning.***[8]

The range of benefits underlying such ideas as the "beneficiaries pay" method of allocating transmission costs have been studied and fully articulated in a 2013 study, also by The Brattle Group,[9] and can be reasonably approximated in the interest of fairness to all ratepayers within the service territory, state, or region served by new transmission capacity. Unfortunately, planners in both RTO/ISO

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[8] Johannes Pfeifenberger, Judy Chang, & Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid* (The Brattle Group 2015) at ii-iii. The report is available at http://www.wiresgroup.com/wires_reports.html.

[9] Judy Chang, Johannes Pfeifenberger, & J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* (The Brattle Group 2013). The report is available at http://www.wiresgroup.com/wires_reports.html.

environments and bilateral markets seldom incorporate all of the potential benefits of proposed projects[10] into the study of project proposals, raising the critical question of whether the new generation of transmission facilities are likely to be the "right" or "best" ones for the electric industry to depend upon for the next half century. The Brattle economists therefore regrettably concluded as follows:

> The risks and costs of inadequate infrastructure typically are not quantified but can be much greater than the costs of the necessary transmission investments. We therefore urge federal and state policy makers to ensure that planning processes include an assessment and documentation of those risks and costs. With an informed understanding and appreciation of those costs and risks, regions will be in a better position to plan a transmission infrastructure that can better protect market participants against these risks. [L]eaving out or discounting the potential costs and risks of not having a sufficiently robust and flexible grid can significantly increase overall electricity cost for consumers and other market participants . . . . [11]

The risks and exposure to future costs associated with a failure to comprehend the benefits of additional transmission are particularly troublesome in the case of interregional transmission planning and coordination. Lest we abandon the potential economic and reliability benefits of interregional and even interconnection-wide transmission in favor of business-as-usual solutions and least common denominator agreements across state and regional lines, WIRES points again to the potential high costs and risks of insufficiently robust and adaptive infrastructure. The Brattle Group again furnishes examples of how adherence to traditional "least cost," "least regrets," and "least common denominator" approaches and to local priorities create barriers to some of the most valuable projects. "[I]nterregional projects face hurdles that are considerably higher than those faced by regional projects. The limitations of the existing interregional planning processes mean that most potential projects will be disqualified, often during the qualifications stage before they are even evaluated."[12]

WIRES looks forward to the fulfillment of Order No. 1000's promise to foster stronger interconnections among regions. However, barriers inherent in current planning processes persist and continue to thwart the best outcomes. The Brattle report recommends specific avenues by which to overcome the obstacles to productive interregional planning and coordination. However, the authors' bottom line recommendation is "that state and federal policy makers encourage transmission planners to pay close attention to the transformation that our power system is undergoing, the risks and costs associated with challenging and extreme

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[10] *Id.* Appendix B is a high-level list of transmission benefits that should be considered by any regional or interregional planning process. It is derived from Brattle's 2013 report, Table 1.

[11] Pfeifenberger, *et al.*, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid* (The Brattle Group 2015) at iv. This report is available at http://www.wiresgroup.com/wires_reports.html.

[12] *Id.* at 36.

market conditions, and the ability of a more robust, flexible transmission infrastructure to reduce the costs and risks of delivering power to consumers."[13] In its oversight role, the Committee can accomplish as much to advance interregional transmission planning and development as it is likely to do with incremental legislative reforms.

ASSESSMENT OF THE PROPOSED BILLS IN LIGHT OF THE NEED FOR TRANSMISSION

As WIRES noted in its recent letter to Senator Martin Heinrich with respect to proposed backstop siting reforms (S. 1017), any measure that will improve the responsiveness of state or federal facilities siting processes is important, especially in leveling the playing field among various modes of energy delivery. "As the Committee considers expediting authorizations of linear energy delivery projects like natural gas pipelines, we urge you and your colleagues not to overlook the fact that the challenges and timelines for electric transmission planning and construction are already *far greater* for companies trying to develop additions to the power grid."

In that regard, the Chair's proposed S. 1217 is a welcome recognition of the successes, however limited, that the Administration has had in helping complex transmission projects obtain the array of permits required from federal agencies. WIRES believes that true interagency coordination can prove critical in specific instances, as it has in the past four years. However, we are afraid that, without systemic reforms to how the accumulated half century of otherwise meritorious environmental measures operate, efforts to persuade various components within multiple federal agencies to work together in a transparent and efficient manner will ultimately prove largely ineffectual in resolving the complexities and challenges created by the magnitude of the transmission and other infrastructure projects that are likely to be proposed.

As it puts together an energy bill, WIRES encourages the Committee to focus on substantially improving the overall quality and timeliness of the existing federal permitting process for electric transmission on federal lands. In that regard, WIRES recommends strengthening S. 1217, Section 2 (b) (1) from "to improve the timeliness and efficiency of electric transmission infrastructure permitting" to actually include a specific timeframe.[14] S. 1217 could be improved by providing the Ombudsperson with authority to set and enforce deadlines applicable to the other agencies participating in the review of a particular project and to require that any extension requests be approved first by the Secretary who has jurisdiction over the requesting agency. Alternatively, WIRES suggests that the Committee consider

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[13] *Id.* at 38.

[14] Berkshire Hathaway Energy's written testimony at the May 14, 2015 hearing suggests 3-4 years, which we view as reasonable/achievable. A January 2013 General Accounting Office study suggests review times could be reduced to 1.5 years with appropriate pre-application meetings. *See* http://www.gao.gov/products/GAO-13-189.

transferring the federal agency coordination responsibilities under Section 216(h) to the FERC, which performs an equivalent coordination function when certificating interstate natural gas pipelines. Either approach would be a marked improvement over the current permitting process for projects involving federally protected lands and resources.

S. 485 is the one piece of legislation under consideration that is likely to slow or arrest needed transmission development. While the bill currently affects one company that has sought to use Section 1222 of the Energy Policy Act of 2005 federal permitting process for almost 5 years now, its potential impact could be much broader. S. 485 would make interstate transmission lines more difficult to site and approve by requiring multiple new steps, including the requirement that transmission projects that are using the Section 1222 federal permitting provisions must be located to the maximum extent practical on federal rights-of-way or federal land managed by the Bureau of Land Management, the U.S. Forest Service, the Bureau of Reclamation, or the Corps of Engineers. S. 485 would also require specific approval from all affected tribes, governors, and public utility commissions. This could add years and millions of dollars to the development cost of interregional transmission facilities, for no obvious public benefit.

As WIRES' comments above clearly indicate, its members agree that modernization of the nation's electric system, including changing outdated technologies and operating practices, is a high priority. We clearly need an adaptable, resilient, and reliable system that delivers for consumers and industry on a regular basis. In that regard, WIRES supports the efforts outlined in S. 1243 and S. 1207 that could contribute to a more robust, flexible system, on the basic assumption that new technologies must be cost-effectively integrated into the system by the network of interstate transmission facilities.

For further information, please contact:

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APPENDIX A

Services Provided by MRAs Relative to Transmission

		Transmission	Energy Efficiency	Demand Response	Utility-scale Generation	Distributed Generation	Energy Storage	Smart Grid - Distribution
What	Energy	●	◑	◑	●	◕	●	●
	Capacity	●	◑	◑	●	◑	◕	○
	Ancillary Services	●	○	◑	●	◕	●	◑
	Reduce system losses	●	◑	◑	○	◔	◔	◔
When	Long lifespan	●	◕	○	◕	●	●	●
	Continuous basis	●	◕	○	◑	○	●	●
Where	Regional	●	◑	◑	●	◔	◔	○
	Local	●	●	●	●	●	●	●
	Micro	●	●	●	○	●	●	●
How	System/Wholesale	●	○	○	●	○	●	○
	Customer/Retail	○	●	●	○	●	○	●
	TOTAL	●	◑	◔	◕	◑	◕	◑

● Provided ○ Not provided

APPENDIX B

Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses b. Reduced congestion due to transmission outages c. Mitigation of extreme events and system contingencies d. Mitigation of weather and load uncertainty e. Reduced cost due to imperfect foresight of real-time system conditions f. Reduced cost of cycling power plants g. Reduced amounts and costs of operating reserves and other ancillary services h. Mitigation of reliability-must-run (RMR) conditions i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects b. Reduced loss of load probability <u>or</u> c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses b. Deferred generation capacity investments c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

WIRES VOICE OF THE ELECTRIC TRANSMISSION INDUSTRY

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May 12, 2015

Hon. Martin Heinrich
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Submitted via email to: dan_alpert@heinrich.senate.gov;
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Dear Senator Heinrich:

WIRES, an international trade association dedicated to promoting investment in critical electric transmission infrastructure (www.wiresgroup.com), wishes to register its appreciation for your leadership regarding the need to upgrade and expand the Nation's high voltage electric transmission infrastructure. WIRES members are publicly-, investor-, and member-owned transmission providers and customers, technology and service companies, and grid managers, in both the U.S. and Canada.

WIRES supports well-planned and environmentally beneficial transmission developments built to provide multiple benefits, whether reliability, economic development, resource diversity, technology modernization, public policy solutions in individual states or nationally, or operational flexibility. Legislation in this Congress, and the willingness of state policymakers to coordinate on infrastructure matters, may decide whether the industry will have regulatory bandwidth to bring meritorious interstate and interregional transmission lines into service in time to ensure that robust electricity markets continue to grow, have diverse energy resources including renewable energy that can reach markets, and that the cost of reliable electricity service remains reasonable for the benefit of consumers and businesses. The ability of all participants in our federal system to identify and implement real solutions is nowhere more important than in the electric power industry.

As the Committee considers expediting authorizations of linear energy delivery projects like natural gas pipelines, we urge you and your colleagues not to overlook the fact that the challenges and timelines for electric transmission planning and construction are already *far greater* for companies trying to develop additions to the power grid. Your proposed legislation highlights one of the challenges that may adversely affect interstate, multi-region, or multi-state projects upon which the country will increasingly rely. It reflects an awareness that the adequacy of the integrated high-voltage grid cannot be ignored or taken for granted. WIRES therefore

commits to you that we will assist your efforts and those of the Committee to ensure that the transmission system will be prepared to serve the evolving needs of the 21st century North American economy.

Respectfully submitted,

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